DEPARTMENT OF THE INTERIOR

Office of Natural Resources Revenue

30 CFR Parts 1206 and 1241

[Docket No. ONRR–2020–0001; DS63644000 DRT000000.CH7000 201D1113RT]

RIN 1012–AA27

ONRR 2020 Valuation Reform and Civil Penalty Rule

AGENCY: Department of the Interior, Office of the Secretary, Office of Natural Resources Revenue.

ACTION: Proposed rule.

SUMMARY: The Office of Natural Resources Revenue (''ONRR'') is publishing this proposed rule to seek comment on measures to amend portions of ONRR's regulations for valuing oil and gas produced from Federal leases for royalty purposes, valuing coal produced from Federal and Indian leases, and assessing civil penalties for violations of certain statutes, regulations, leases, and orders associated with mineral leases.

DATES: You must submit comments on or before November 30, 2020.

ADDRESSES: You may submit comments to ONRR using any of the following three methods. Please reference Regulation Identifier Number (RIN) 1012–AA27 in any comment:

- Electronically submit at *http://www.regulations.gov*. In the search bar titled ''SEARCH for: Rules, Comments, Adjudications or Supporting Documents:'' enter ''ONRR–2020–0001,'' and then click ''Search.'' Follow the instructions to submit public comments.
- Email comments to Dane Templin, Regulations Supervisor, at *Dane.Templin@onrr.gov* and Luis Aguilar, Regulatory Specialist, at *Luis.Aguilar@onrr.gov*. Include RIN 1012–AA27 in the subject line of the message.
- Hand-carry or mail comments to the Office of Natural Resources Revenue, Building 85, Entrance N–1, Denver Federal Center, West 6th Ave. and Kipling St., Denver, Colorado 80225.

Instructions: All comments must include the agency name and docket number or RIN for this rulemaking. All comments, including any personal identifying information or confidential business information contained in a comment, will be posted without change to *https://www.onrr.gov/Laws_R_D/FRNotices/AA27.htm*. See also Public Availability of Comments under the Procedural Matters section of this document.

Docket: For access to the docket to read background documents or comments received, go to *https://regulations.gov* or *https://www.onrr.gov/Laws_R_D/FRNotices/AA27.htm*.

FOR FURTHER INFORMATION CONTACT: For questions on procedural issues, contact Dane Templin at (303) 231–3149, or by email addressed to *Dane.Templin@onrr.gov*. For comments or questions on technical issues, contact Amy Lunt, Supervisor Royalty Valuation Team A, at (303) 231–3746, or by email addressed to *Amy.Lunt@onrr.gov,* or Peter Christnacht, Supervisor Royalty Valuation Team B, at (303) 231–3651, or by email addressed to *Peter.Christnacht@onrr.gov*.

SUPPLEMENTARY INFORMATION:

I. Executive Summary

ONRR is proposing, for multiple reasons, targeted amendments to 30 CFR part 1206 (most recently amended by the 2016 Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform Rule (''2016 Valuation Rule'')). First, the 2016 Valuation Rule added certain provisions that are inconsistent with multiple executive orders that have been issued after the 2016 Valuation Rule's effective date, including Executive Order on Promoting Energy Independence and Economic Growth (Executive Order 13783), which directs agencies to ''identify existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law.'' Second, ONRR, after defending its amendments to the Federal and Indian coal valuation rules in 2016 Valuation Rule litigation, and upon consideration of the parties' briefs and receiving the Court's ruling, has determined that it should propose a revision to the most controversial coal valuation rules. Third, the proposed amendments would update ONRR's regulations to simplify certain processes, provide early clarity regarding royalties owed, and better explain ONRR's civil penalty practices. Finally, this proposed rule would return the relationship between the Federal government, States, Tribes, and regulated parties to the longstanding and familiar valuation framework that existed under FOGRMA for many years prior to the 2016 Valuation Rule. The agency finds that these reasons, collectively and individually, warrant amending ONRR's valuation and civil penalty regulations.

In addition, ONRR proposes to amend 30 CFR part 1241 (most recently amended by the 2016 Amendments to Civil Penalty Regulations (''2016 Civil Penalty Rule'')) to conform that part with a decision recently issued by a federal district court and to clarify that the 2016 Civil Penalty Rule conforms with ONRR's long-standing practice.

ONRR believes that regulatory certainty will be best served by amending targeted portions of 30 CFR part 1206 that the 2016 Valuation Rule also addressed, including recodifying certain pre-2017 regulations to achieve a more rational balance between the government's interest in effective regulation of royalties and the burden on the regulated entities. Though ONRR recognizes that the regulations in place prior to the 2016 Valuation Rule pose certain implementation challenges, the agency finds that restoring those prior regulations is preferable to maintaining ONRR's rules, as modified by 2016 Valuation Rule, because returning to some of the prior regulations would reinstate a longstanding, nationwide regulatory framework that is better understood by the parties interpreting and applying the regulations (ONRR and the regulated entities). The proposed rule would also meet policy objectives stated in certain Executive Orders, including Executive Order 13783, ''Promoting Energy Independence and Economic Growth,'' Executive Order 13795, ''Implementing an America-First Offshore Energy Strategy,'' and would support Secretarial Order 3350, which promotes the America-First Offshore Energy Strategy.

In July 2016, ONRR published the 2016 Valuation Rule, amending, in a number of significant respects, the valuation regulations applicable to Federal oil and gas and Federal and Indian coal. 81 FR 43338, July 1, 2016 (*https://www.onrr.gov/Laws_R_D/FRNotices/AA13.htm*). The effective date of the 2016 Valuation Rule was January 1, 2017. ONRR is reissuing the 2016 Valuation Rule in the Rule and Regulations section of this issue of the **Federal Register**.

With respect to Federal oil and gas, this proposed rule would alter or reverse some of the changes brought about by the 2016 Valuation Rule in order to return to the definitions and practices that had been in place since the 1980s. The proposed changes to return to historical practices include: (1) Reinstating the ability of a lessee to request to exceed the 50-percent regulatory limit for transportation costs; (2) reinstating the ability of a lessee to request to exceed the 66 2/3-percent regulatory limit for processing costs; (3) allowing a lessee producing offshore to claim, without requesting case-by-case approval, certain gathering costs as a transportation allowance in waters 200 meters and deeper; (4) allowing a lessee producing offshore to request ONRR's approval to claim certain gathering costs as a transportation allowance in waters shallower than 200 meters where ''deepwater-like'' subsea movement occurs; (5) removing the misconduct definition (also applies to Federal and Indian coal); (6) removing the default provision and all references thereto (also applies to Federal and Indian coal); (7) eliminating the requirement that written contracts be signed by all parties (also applies to Federal and Indian coal); and (8) eliminating the requirement that companies cite legal precedent when seeking a valuation determination (also applies to Federal and Indian coal). In addition, this proposed rule would expand concepts first adopted in the 2016 Valuation Rule. The proposed expansion to those 2016 Valuation Rule concepts includes extending the index-based valuation option to all Federal gas dispositions. Finally, this proposed rule would change a few index-based valuation concepts in the 2016 Valuation Rule, including changing the index-based option for unprocessed and residue gas from the highest bidweek price to an average bidweek price; updating the index-based transportation deductions based on more current data; expressly stating that a lessee cannot report royalty values of zero or less; and, expressing that ONRR can request production of a variety of records from lessees who report under an index-based option.

By reverting to certain pre-2016 Valuation Rule practices, this rule would reintroduce one ONRR-quantified administrative cost that the 2016 Valuation Rule eliminated—accounting for deepwater gathering costs that may be claimed as part of a transportation allowance. Described further in Section E, ONRR estimates that Federal lessees would incur an additional $3.136 million in administrative costs in order to increase reported transportation allowances by $30.5 to $41.3 million per year related to deepwater gathering.

With respect to Federal and Indian coal, this proposed rule would eliminate some of the changes brought about by the 2016 Valuation Rule in order to address deficiencies in the 2016 Valuation Rule identified by the United States District Court for the District of Wyoming in *Cloud Peak Energy, Inc.,* v. *U.S. Dep't of the Interior,* 415 F. Supp. 3d 1034 (D. Wy. 2019). Specifically, this proposed rule would remove the requirement that coal be valued based on sales of electricity and eliminate the definition of coal cooperative.

In August 2016, ONRR published the 2016 Civil Penalty Rule. 81 FR 50306, August 1, 2016 (*https://www.onrr.gov/Laws_R_D/FRNotices/AA05.htm*). This proposed rule would change the regulations to conform to the decision issued in *American Petroleum Institute (''API'')* v. *U.S. Dep't of the Interior,* 366 F. Supp. 3d 1292, 1309–10 (D. Wyo. 2018), by eliminating the Department's administrative law judges' ability to reverse a stay of the accrual of civil penalties upon a showing that the lessee's defense to a civil penalty notice was ''frivolous.'' In addition, this proposed rule would clarify ONRR's long-standing practice with respect to aggravating and mitigating circumstances, and the information that ONRR considers in assessing the amount of a civil penalty to issue in a case involving violations of a lessee's obligation to pay money to the United States (a ''payment violation'').

A. ONRR's Prior Related Rulemaking and Associated Litigation

1. Federal Oil and Gas and Federal and Indian Coal

Prior to January 1, 2017, the royalty valuation framework for Federal oil and gas and Federal and Indian coal was based on regulations published in 1988 and 1989. After ONRR published the 2016 Valuation Rule, several industry groups filed lawsuits to challenge the 2016 Valuation Rule in the U.S. District Court for the District of Wyoming on December 29, 2016.

On February 17, 2017, the petitioners requested that ONRR postpone implementation of the 2016 Valuation Rule, and alleged that the rule would create widespread uncertainty and render compliance impossible. On February 27, 2017, ONRR published a Postponement Notice in the **Federal Register**, 82 FR 11823. In response to the Postponement Notice, California and New Mexico filed a lawsuit in the U.S. District Court for the Northern Division of California that alleged ONRR's action violated the Administrative Procedure Act (APA). The presiding magistrate judge concluded that ONRR's postponement of the 2016 Valuation Rule violated the APA. *See Becerra* v. *U.S. Dep't. of the Interior,* 276 F. Supp. 3d 953, 967 (N.D. Cal. 2017).

On April 4, 2017, ONRR published a proposed rule in the **Federal Register** to repeal the 2016 Valuation Rule in its entirety, 82 FR 16323 (*https://www.onrr.gov/Laws_R_D/FRNotices/PDFDocs/16323.pdf*). Then, on August 7, 2017, ONRR published the Repeal of Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform final rule, which repealed the 2016 Valuation Rule in its entirety (''2017 Repeal Rule''), 82 FR 36934 (*https://www.onrr.gov/Laws_R_D/FRNotices/AA20.htm*). In response to the repeal, industry dismissed the lawsuits challenging the 2016 Valuation Rule and, on October 7, 2017, the States of California and New Mexico filed litigation to challenge the 2017 Repeal Rule.

On March 29, 2019, the United States District Court for the Northern District of California issued a decision in the case filed by the States of California and New Mexico, vacating ONRR's 2017 Repeal Rule (''2019 Vacatur''). *California,* v. *U.S. Dep't of the Interior,* 381 F. Supp. 3d 1153 (N.D. Cal. 2019). The 2019 Vacatur reinstated the 2016 Valuation Rule, including its effective date of January 1, 2017. One of the district court's findings in the case was that ONRR failed to adequately explain the regulatory change.

First, the district court held that ONRR did not provide a reasoned explanation as to ''why the industry concerns [regarding compliance issues with the 2016 Valuation Rule that ONRR] previously rejected—as well as its prior findings in support of adopting the [2016 Valuation Rule]—now justified returning to the pre-[2016 Valuation Rule] regulatory framework. Nowhere in the Final Repeal does the ONRR provide such an explanation.'' *Id.* at 1166 (citation omitted). The district court went on to state that ''[a]lthough the ONRR is entitled to change its position, it must provide 'a reasoned explanation . . . for disregarding facts and circumstances that underlay or were engendered by the prior policy.''' *Id.* at 1168. ''ONRR's conclusory explanation in the Final Repeal fails to satisfy its obligation to explain inconsistencies between its prior findings in enacting the [2016 Valuation Rule] and its decision to repeal such Rule.'' *Id.*

Second, the district court held that there was no support for ONRR's complete repeal of the 2016 Valuation Rule. *Id.* ''When considering revoking a rule, an agency must consider alternatives in lieu of complete repeal, such as by addressing the deficiencies individually.'' *Id.* The court found that such action was arbitrary and capricious. *Id.* at 1169 (citing *California* v. *Bureau of Land Mgmt.,* 286 F. Supp. 3d 1054, 1066–67 (N.D. Cal. 2018) (finding that even if the agency had factual evidence to support its claim that the new regulations at issue in that rule burdened small operators, a ''blanket suspension'' of the regulations was arbitrary and capricious because the suspension was ''not properly tailored'' to address the allegedly defective provision)).

Third, the district court found that ONRR's citation to Executive Order 13783 as justification for repeal of the 2016 Valuation Rule was not adequately explained and conclusory. *Id.* at 1169–70. ''More fundamentally, the ONRR's speculation that provisions [in the 2016 Valuation Rule] would be unduly burdensome, difficult to apply and increase costs, directly contradict its previous findings in its promulgation of the [2016 Valuation Rule].'' *Id.* at 1170. The court concluded that an agency's failure to provide a reasoned explanation for its decision to suspend a rule based on the rule's costs, while ignoring its benefits, violates the APA. *Id.*

Fourth, the district court found that ONRR could not rely on potential future findings and recommendations made by its Royalty Policy Committee to justify repeal of the 2016 Valuation Rule, although ONRR stated it was not, in any event, doing so. *Id.* at 1171. ''Predicating a repeal decision on recommendations that may or may not occur in the future is arbitrary and capricious.'' *Id.*

After ONRR reinstated the 2016 Valuation Rule, industry refiled litigation challenging the 2016 Valuation Rule. That litigation is currently proceeding in the United States District Court for the District of Wyoming. *Cloud Peak Energy, Inc.* v. *U.S. Dep't of the Interior,* Case No. 19–CV–120–SWS (D. Wyo.). On October 8, 2019, the Wyoming District Court entered an Order granting in part and denying in part industry's request for a preliminary injunction of the implementation of the 2016 Valuation Rule. The Court refused to enjoin the portions of the 2016 Valuation Rule applicable to Federal oil and gas but stayed the portions of the 2016 Valuation Rule applicable to Federal and Indian coal. *Cloud Peak,* 415 F. Supp. 3d at 1053. Thus, the 1989 Federal and Indian Coal Valuation Regulations continue to govern coal valuation produced from Federal and Indian leases.

Through two ''Dear Reporter'' letters (dated June 13, 2019, and November 20, 2019), ONRR has provided reporters and payors until July 1, 2020, to comply with the portions of the 2016 Valuation Rule applicable to Federal oil and gas (*https://www.onrr.gov/PDFDocs/Dear-Reporter-Letter-2016-Rule.pdf* and *https://www.onrr.gov/PDFDocs/dear-reporter-letter-20-Nov-19.pdf*).

2. Civil Penalties

On August 1, 2016, the 2016 Civil Penalty Rule was published. 81 FR 50306 (*https://www.onrr.gov/Laws_R_D/FRNotices/AA05.htm*). In the *API* case, *supra,* the 2016 Civil Penalty Rule withstood industry's challenge, with the exception of the challenge to 30 CFR 1241.11(b)(5), which related to the Department's administrative law judges' power to stay civil penalty accruals pending appeal. 366 F. Supp. 3d at 1311. API has appealed the District Judge's decision on the remaining portions of the 2016 Civil Penalty Rule and that appeal is pending in the United States Court of Appeals for the Tenth Circuit. *API* v. *U.S. Dep't of the Interior,* Case No. 18–8070 (10th Cir.).

B. Rulemaking Objectives

This rulemaking is not founded upon new factual findings contradicting those upon which the 2016 Valuation Rule was based. Instead, ONRR is implementing this rulemaking because policy directives issued after July 1, 2016, give different weight to the factual findings, and also dictate that a different policy-based outcome be pursued.

A revised rulemaking based on ''a reevaluation of which policy would be better in light of the facts'' is ''well within an agency's discretion.'' *Nat'l Ass'n of Home Builders* v. *EPA,* 682 F.3d 1032, 1038 (D.C. Cir. 2012) (citing *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502, 514–15 (2009)). Further, ''[a] change in administration brought about by the people casting their votes is a perfectly reasonable basis for an executive agency's reappraisal of the costs and benefits of its programs and regulations.'' *Id.* at 1043 (quoting *Motor Vehicle Mfrs. Ass'n of the U.S., Inc.* v. *State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29, 59 (1983) (Rehnquist, J., concurring in part and dissenting in part)). An ''agency is entitled to have second thoughts, and to sustain action which it considers in the public interest upon whatever basis more mature reflection suggests.'' *Dana Corp.* v. *ICC,* 703 F.2d 1297, 1305 (D.C. Cir. 1983). An agency is entitled to give more weight to socioeconomic concerns than it may have under a different administration. *Organized Vill. of Kake* v. *U.S. Dep't. of Agric.,* 795 F.3d 956, 968 (9th Cir. 2015) (en banc).

In determining that ONRR should reconsider its rules, it considered Executive Order 13783, ''Promoting Energy Independence and Economic Growth;'' Executive Order 13795, ''Implementing an America-First Offshore Energy Strategy;'' and Secretarial Orders 3350 and 3360, which promote the America-First Offshore Energy Strategy and require a review of regulations that ''potentially burden the development or utilization of domestically produced energy resources,'' respectively. These Executive and Secretarial Orders directed review of various agency actions, without directing specific outcomes for rulemakings.

1. Executive Order 13783, Promoting Energy Independence and Economic Growth, March 28, 2017

In Executive Order 13783, the President emphasized that ''[i]t is in the national interest to promote clean and safe development of our Nation's vast energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation.'' The President further directed executive departments and agencies to immediately review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law. Pursuant to Executive Order 13783, agency heads are required to review all existing regulations that potentially burden the development or use of domestically produced energy resources, ''with particular attention to oil, natural gas, coal, and nuclear energy resources.'' Executive Order 13783 further explained that ''burden'' means to unnecessarily obstruct, delay, curtail, or otherwise impose significant costs on the siting, permitting, production, utilization, transmission, or delivery of energy resources.

2. Executive Order 13795, Implementing an America-First Offshore Energy Strategy, April 28, 2017

Through Executive Order 13795, the President stated his policy goal of emphasizing ''the energy needs of American families and businesses first'' and to ''continue implementing a plan that ensures energy security and economic vitality for decades to come.'' The Executive Order 13795 stated that ''[i]ncreased domestic energy production on Federal lands and waters strengthens the Nation's security and reduces reliance on imported energy'' as well as helping reinvigorate American manufacturing and job growth.

Accordingly, Executive Order 13795 stated that ''[i]t shall be the policy of the United States to encourage energy exploration and production, including on the Outer Continental Shelf (OCS), in order to maintain the Nation's position as a global energy leader and foster energy security and resilience for the benefit of the American people . . . .''

3. Secretarial Orders 3350 and 3360

Two Secretarial Orders are also relevant to this rulemaking. Through Secretarial Order 3350, America-First Offshore Energy Strategy, the Secretary of the Interior (Secretary) took specific steps to implement Executive Order 13795. Significant to the proposed rule, the Secretary specifically stated that Secretarial Order 3350 is designed to implement the President's directives as set forth in Executive Order 13795 to ''ensure that responsible OCS exploration and development is promoted and not unnecessarily delayed or inhibited.'' The Order directed Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement to take specific actions, but also more generally expressed a desire for active coordination of energy policy in order to enhance opportunities for energy exploration, leasing, and development on the OCS. Secretarial Order 3360 is likewise directed at continuing to implement Executive Order 13783 and the directive to the Department to review existing regulations that ''potentially burden the development or utilization of domestically produced energy resources.''

These Executive Orders and Secretarial Orders make clear that it is in the national interest to promote domestic energy development for a variety of reasons, including stimulating the economy, job creation, and national security. They also emphasize the importance of reducing regulatory burdens so that energy producers, and particularly oil, natural gas, and coal producers, can be encouraged to produce more energy. Through this rulemaking, ONRR will attempt to further those policy objectives by two primary means. The first, to provide mechanisms that simplify reporting. The second, to promote new and continued domestic energy production. In Section F below, ONRR requests specific comments on how effectively the proposed rule would implement the policy objectives stated above, and for additional ways in which ONRR could further implement those policy objectives.

ONRR's royalty program is ''a complex and highly technical regulatory program, in which the identification and classification of relevant criteria necessarily require significant expertise and entail the exercise of judgment grounded in policy concerns.'' *Amoco Prod. Co.* v. *Watson,* 410 F.3d 722, 729 (D.C. Cir. 2005) (internal quotations and citation omitted). FOGRMA grants the Secretary authority to ''prescribe such rules and regulations as he deems reasonably necessary to carry out this chapter.'' *See* 30 U.S.C. 1751(a); *see also, e.g.,* 30 U.S.C. 1719. Re-evaluating the best means of balancing these statutory priorities within the bounds of the specific commands of the statute, as called for in the Executive and Secretarial Orders, is well within the scope of authority that Congress delegated to ONRR under FOGRMA.

C. ONRR's Rulemaking Authority

Congress gave the Secretary authority to promulgate regulations concerning ''a comprehensive inspection, collection and fiscal and production accounting and auditing system to provide the capability to accurately determine oil and gas royalties, interest, fines, penalties, fees, deposits, and other payments owed, and to collect and account for such amounts in a timely manner.'' 30 U.S.C. 1711(a). The Secretary, in turn, assigned these duties to ONRR's predecessor, a program within the Minerals Management Service. 47 FR 4751, February 2, 1982; Secretarial Order 3071, as amended on May 10, 1982; *see also* 30 CFR 201.100 (2006). Secretarial Order 3299, as amended on August 29, 2011, created ONRR and delegated to it the ''royalty and revenue management function of the Minerals Management Service.''

ONRR has the authority to amend its rules, consistent in large part with the policy established in the Executive and Secretarial Orders, so long as ONRR: (1) Displays ''awareness that it is changing position,'' (2) shows that ''the new policy is permissible under the statute,'' (3) ''believes'' that the new policy is better than the old, and (4) provides ''good reasons'' for the new policy, which, if the ''new policy rests upon factual findings that contradict those which underlay its prior policy,'' must include ''a reasoned explanation . . . for disregarding facts and circumstances that underlay or were engendered by the prior policy.'' *Fox,* 556 U.S. at 515–16.

Importantly, ONRR is not limited to an analysis of whether facts or circumstances changed since the 2016 Valuation Rule. Instead, ONRR may look to other ''good reasons'' to adopt new policy—including the objectives of certain Executive and Secretarial Orders and weighing facts differently considering those objectives.

ONRR does not need to base a revised decision upon a change of facts or circumstances. A revised rulemaking based ''on a reevaluation of which policy would be better in light of the facts'' is ''well within an agency's discretion,'' and ''[a] change in administration brought about by the people casting their votes is a perfectly reasonable basis for an executive agency's reappraisal of the costs and benefits of its programs and regulations.'' *Nat'l Ass'n of Home Builders,* 682 F.3d at 1038 and 1043 (citations omitted).

D. What This Proposed Rule Does

1. Index-Based Options for Valuing Federal Gas

The 2016 Valuation Rule adopted an index-based valuation option for non-arm's-length sales (that is, sales under contracts that do not satisfy the ''arm's-length contract'' definition under § 1206.20 or sales that do not occur under a contract) of unprocessed gas, natural gas liquids (''NGLs''), and residue gas. The 2016 Valuation Rule set royalty value at the highest monthly bidweek price (less a specified deduction) for unprocessed gas and residue gas, and the average monthly bidweek price (less a specified deduction) for NGLs, from a publicly-available publication at an accessible index-pricing point. Currently approved publications can be found at *https://www.onrr.gov/Valuation/federal-gas-index-option.htm*.

In the 2016 Valuation Rule, ONRR explained that the gross proceeds accruing under an arm's-length transaction is generally the most accurate indicator of value. But given the complexity of non-arm's-length dispositions, it was appropriate to provide the index-based valuation option to increase simplicity and reduce administrative burdens to ONRR and industry.

Complex valuation situations related to marketable condition, transportation, and processing are not limited to non-arm's-length dispositions. So similar benefits—notably reductions to industry's administrative burdens—could be gained by extending the index-based valuation option to arm's-length dispositions. Further, because industry is in the process of altering its accounting and reporting processes to monitor and use index-based valuation for its non-arm's-length dispositions, it stands to gain additional efficiencies from applying those same processes to arm's-length dispositions.

ONRR maintains that arm's-length dispositions are most often the strongest indicator of market value, and that market value is generally the most appropriate measure for royalty value. This proposed rule would attempt to further the 2016 Valuation Rule's progress by closing the gap between royalty values determined using the gross proceeds accrued under arm's-length dispositions and royalty values determined under index-based valuation.

In the 2016 Valuation Rule, ONRR designed the index-based valuation option to result in royalty values that are generally greater than those based on gross proceeds. The greater value protected ONRR's ability to collect at least as much in royalties using index-based valuation as it would using a non-index method (that is, using gross proceeds). ONRR stated that any increase in royalty value would be offset by the reduced administrative burden that the index-based option's simplicity and clarity afforded a lessee. Based on a review of data from production months in 2007 through 2010, ONRR determined that the estimated royalty value using an index-based valuation option would result in consistently higher royalties due than the average value received under gross-proceeds-based reporting.

When ONRR uses the term, ''published average bidweek price,'' or ''bidweek average'' for short, it refers to what many publications call the ''index'' or ''average'' price. For example, the *Platts Inside FERC's Gas Market Report* labels this price as the ''index,'' while the *Natural Gas Intelligence's (NGI) Bidweek Survey* labels this price as the ''average.''

ONRR proposes to amend 30 CFR part 1206 to specify that, when a lessee chooses to value unprocessed or residue gas for royalty purposes using the index-based option, the lessee may use the published bidweek average price rather than the bidweek high price. Doing so should more closely match what many lessees would otherwise receive as gross proceeds and would apply a consistent valuation approach to unprocessed gas, residue gas, and NGLs.

ONRR compared the royalties paid based on gross proceeds to the royalties paid using the 2016 Valuation Rule's index-based valuation option—as well as to the method proposed in this rule. As outlined in the Procedural Matters section, overall royalty values under the 2016 Valuation Rule's index-based valuation option are still around $0.04/MMBtu higher than the prices reported to ONRR for arm's-length sales. In the proposed rule, the average bidweek price would result in around $0.09 less per MMBtu. But, in certain areas, there could be greater increases (offshore Gulf of Mexico) or decreases (most onshore basins) in royalty value under the index-based valuation option. ONRR is interested in receiving comments on alternatives that more closely match the index-based valuation method to the gross proceeds accruing under arm's-length dispositions across all Federal oil and gas leases.

Through the proposed rule, ONRR is attempting to address major concerns with the 2016 Valuation Rule's index-based valuation option for Federal gas and implement certain Administration policies enacted following publication of the 2016 Valuation Rule to encourage domestic oil and gas production and reduce undue regulatory burdens on industry. The proposed rule would: (1) Extend the index-based valuation option to all Federal gas dispositions; (2) change the royalty value under the index-based option for unprocessed and residue gas from the highest bidweek price to the average bidweek price; (3) update the index-based transportation deduction to rely on more recent cost data; (4) clarify, in the unprocessed and processed gas sections, that a lessee may not report a product's value for royalty purposes as zero or less; and (5) add language reinforcing ONRR's statutory authority to request and receive a lessee's and its affiliate's sales and expense records even in instances where the lessee pays royalties under an index-based valuation method.

2. Allowance Limits

For over two decades before the 2016 Valuation Rule, when a lessee submitted a certain form (form ONRR–4393), and documentation showing that it had met certain criteria, ONRR would evaluate the submissions and determine whether to allow that lessee to exceed the regulatory limits for transportation allowances or processing allowances (request-to-exceed), or, under a different process, to claim extraordinary processing costs (request-to-claim). The 2016 Valuation Rule eliminated those practices by converting the regulatory limits into hard caps, abolishing the request-to-exceed and request-to-claim processes, and terminating all approvals ONRR previously granted.

ONRR has re-evaluated these provisions in light of the Administration's policy emphasis on domestic energy production and reduction of regulatory burdens and believes it is appropriate to reconsider the allowance limits in light of the burdens the 2016 Valuation Rule imposed. The 2016 Valuation Rule's allowance hard caps increased energy production costs (through increased royalty values) in situations where a lessee previously had a long-standing ability to deduct certain costs under the 1988 valuation rule after justifying its request for an allowance. Providing a lessee with a method to request and receive approval to exceed the regulatory limits removes a disincentive for the limited number of lessees that produce from Federal lands that are less desirable due to the high costs associated with transportation, processing, or both. In particular, reintroducing the request-to-exceed and request-to-claim processes could remove a hard cap's disincentive to produce in remote areas (high movement costs) or from low quality reservoirs (high treatment costs, processing costs, or both). It could also provide a lessee an incentive to continue producing through uncommon or unavoidable circumstances affecting costs and value.

ONRR proposes to remove the undue burden on energy production that the 2016 Valuation Rule's hard caps created when the rule eliminated the approval burden for ONRR. The proposed rule would revert to the historical practices with respect to regulatory limits on transportation costs (50 percent for Federal oil and Federal gas) and processing costs (66⅔ percent for Federal gas), and allow a lessee to request extraordinary processing-cost allowance approvals. As before the 2016 Valuation Rule, ONRR would only approve a lessee's request after reviewing a lessee's documentation for adequacy, reasonableness, and accuracy.

3. Transportation Allowance for Certain Offshore Gathering Costs

After the publication of 2016 Valuation Rule, the Administration adopted policies through certain Executive and Secretarial Orders to encourage Federal oil and gas production. In response, ONRR is reexamining its historical practice (1999 through 2016) with respect to allowing a transportation deduction for certain costs that the regulations define to be gathering costs. Specifically, ONRR proposes to reinstate the May 20, 1999, memorandum titled ''Guidance for Determining Transportation Allowances for Production from Leases in Water Depths Greater Than 200 Meters.''

In 1988, the Minerals Management Service (MMS) defined ''gathering'' in regulations for the first time (and it has remained substantively unchanged since): '''Gathering' means the movement of lease production to a central accumulation and/or treatment point on the lease, unit or communitized area, or to a central accumulation or treatment point off the lease, unit or communitized area as approved by BLM or MMS OCS operations personnel for onshore and OCS leases, respectively.'' *See* 53 FR 1273, January 15, 1988.

In effect, those regulations authorized a lessee to deduct certain costs incurred for transportation off the lease—other than gathering—as a transportation allowance. In the final rule, MMS rejected an industry-group's comment to remove the ''excluding gathering'' language because ''MMS [believed] that gathering is a cost of making oil marketable, which must be borne exclusively by the lessee.'' 53 FR 1184 at 1190–1191, January 15, 1988.

MMS also considered numerous comments from industry concerning the phrase ''or to a central accumulation or treatment point off the lease, unit or communitized area as approved by BLM or MMS OCS operations personnel for onshore and OCS leases, respectively.'' The commenters stated that the phrase was unclear and that it should be removed from the definition. Several industry commenters recommended that gathering be limited to the lease or unit area so a transportation allowance could be obtained for all off lease movement. But MMS kept the proposed rule's definition intact.

The operational regulations of both BLM and MMS required that a lessee place all production in a marketable condition, if economically feasible, and that a lessee also properly measure all production in a manner acceptable to those agencies' authorized officials. Unless specifically approved otherwise, the regulations' requirements were to be met prior to the production leaving the lease. Thus, MMS did not believe that any allowances should be granted for costs incurred by a lessee when approval was granted for the removal of production from the lease, unit, or communitized area when the purpose was to treat production or accumulate production for delivery to a purchaser prior to meeting the requirements of any operational regulations. 53 FR 1184 at 1193, January 15, 1988.

MMS published the 1988 rule prohibiting the deduction of all gathering costs with knowledge of the costs of deepwater gathering. While the 1987 draft final rule that preceded the 1988 rule contemplated allowing deductions for deepwater gathering costs, the 1988 rule rejected any deduction for deepwater gathering costs. The 1987 draft final rule provided that if a lessee incurs extraordinary costs for gathering from frontier or deepwater areas, and those costs related to unusual or unconventional operations, it may apply to MMS for an allowance. Such an allowance would only be granted if the costs were associated with offshore leases located in water depths in excess of 400 meters. 52 FR 30826 at 30858, August 17, 1987.

But in the preamble to the 1988 rule MMS concluded that it would not allow a deduction of any gathering costs, including deepwater gathering. MMS concluded that the burdens placed on the lessee by the environment in which it operates were matters considered at the time the lease was issued, and reflected in the amount of bonus bids and, in some cases, the royalty rate. MMS determined that if a lessee was entitled to further economic relief, it would be inappropriate to provide that relief through an adjustment to the value of the production using methods that were inconsistent with historical practice and interpretation of a lessee's express obligation to place production in marketable condition at no cost to the Federal lessor. 53 FR 1184 at 1205 (January 15, 1988).

In sum, ONRR and its predecessor, MMS, by regulation prohibited the deduction of all gathering, even for deepwater, with gathering defined to include all movement upstream of any ''central accumulation point and/or treatment point.'' Preamble language clarified upstream of a ''central accumulation point and/or treatment point'' to mean upstream of the point at which oil and gas is in marketable condition and metered for royalty purposes.

In 1998, MMS published two **Federal Register** Notices (63 FR at 38355 and 63 FR 56217) requesting input on whether MMS should change the ''gathering'' definition to allow a lessee to deduct costs associated with moving bulk production from subsea wellheads to offshore floating platforms. MMS requested further comments on what criteria to use when differentiating between the movement that is gathering and the movement that is transportation.

MMS chose not to amend its regulations after receiving comments on those **Federal Register** notices. Instead, the Associate Director for MMS's Royalty Management Program implemented policy on deepwater gathering through a May 20, 1999, memorandum titled ''Guidance for Determining Transportation Allowances for Production from Leases in Water Depths Greater Than 200 Meters'' (Deepwater Policy).

The Deepwater Policy provided that production from a lease, any part of which lies in water deeper than 200 meters, may qualify for a transportation allowance. The following guidelines also applied:

- The transportation allowance was to be determined in accordance with then-current regulations.
- The costs of movement was allocated between the royalty bearing and non-royalty bearing substances.
- Movement prior to a central accumulation point was considered gathering. A central accumulation point may be a single well, a subsea manifold, the last well in a group of wells connected in series, or a platform extending above the surface of the water. Movement beyond the point was considered transportation.
- Leases and units were treated similarly.
- To qualify for a transportation allowance, the movement had to be to a facility not located on a lease adjacent to the lease on which the production originated. An adjacent lease was defined as any lease with at least one point of contact with the producing lease/unit. Typically, for a single lease, there would be eight leases adjacent to a qualifying deep-water lease.
- Allowances for subsea completions not located in water deeper than 200 meters could be considered on a case-by-case basis.

In the proposed 2016 Valuation Rule (80 FR 608), ONRR proposed to rescind the Deepwater Policy because, ''Under Kerr-McGee Corp., 147 IBLA 277, 282 (Jan. 29, 1999) almost all of the movement the [Deepwater] Policy allows as a transportation allowance is, in actuality, non-deductible 'gathering' under ONRR's current valuation regulations. We determined that the Deep-Water Policy is inconsistent with our regulatory definition of ''gathering'' and Departmental decisions interpreting that term.'' *Id.* at 624.

In the 2016 Valuation Rule's preamble, ONRR included language that rescinded the Deepwater Policy, explaining that MMS intended for the Deepwater Policy to incentivize deepwater leasing by allowing lessees to deduct broader transportation costs than the regulations allowed. ONRR then concluded that the Deepwater Policy had served its purpose and was no longer necessary.

In the 2017 Repeal Rule, ONRR stated that by reinstating the prior regulations, ONRR's longstanding Deepwater Policy would remain in effect, and that ONRR would continue to implement the Deepwater Policy to the extent that it is consistent with the prior regulations. ONRR also asserted that the Deepwater Policy is a matter that is appropriate to revisit and reconsider. Industry endorsed ONRR's attempt to revive the policy and public interest groups opposed the effort arguing the Deepwater Policy allowed, in the form of a transportation allowance, an ''improper deduction under ONRR's regulatory scheme.''

As discussed above, ONRR is in the process of reevaluating its rules in light of Executive Orders 13783 and 13795, which call on Federal agencies to promote and unburden domestic energy production, and the Secretarial Orders encouraging robust and responsible exploration and development of Outer Continental Shelf (OCS) resources.

A subsea completion exists where the wellhead is located on the seafloor, and bulk production is moved to the production platform through a series of manifolds and flow lines. This is different—and significantly more complex—than a topside completion, where the wellhead is located on a platform above the water surface. A deepwater lessee must typically move offshore production great distances relative to other areas before it reaches the wellhead—where separation, treatment, and measurement for royalty purposes may occur. Due to the unique environmental and operational factors in deepwater, a lessee may be unable (without great costs, impaired engineering efficiency, or both) to satisfy ONRR's ''gathering'' definition before production reaches the platform.

The proposed rule would effectively revert to ONRR's historical policy (1999 to 2016) that was embodied in the Deepwater Policy and permitted a lessee producing from the OCS to take a transportation allowance for certain costs that the pre-2016 rules defined as gathering costs.

ONRR proposes to remove the language in the ''gathering'' definition under § 1206.20 defining ''gathering'' to include ''any movement of bulk production from the wellhead to a platform offshore.'' ONRR also proposes to remove the language that the 2016 Valuation Rule added in the transportation allowance sections under §§ 1206.110(a)(2)(ii) and 1206.152(a)(2)(ii) that provides ''[f]or [production from] the OCS, the movement of [production] from the wellhead to the first platform is not transportation.'' ONRR proposes to replace the removed language from language consistent with the Deepwater Policy for production from water deeper than 200 meters and water shallower than 200 meters. For example, the Federal oil regulations under § 1206.110 would state that: ''For oil produced on the OCS in waters deeper than 200 meters, the movement of oil from the wellhead to the first platform is transportation for which a transportation allowance may be claimed'' and ''On a case-by-case basis, you may apply to ONRR to have your actual, reasonable and necessary costs of the movement of oil produced on the OCS in waters shallower than 200 meters from the wellhead to the first platform to be treated as transportation for which a transportation allowance may be claimed.''

4. Misconduct, the Default Provision, and Contract Signature Requirement

ONRR proposes to amend certain sections under 30 CFR part 1206 to effectively return the requirements for the following topics, for Federal oil and gas and Federal and Indian Coal, to the practices in place prior to the 2016 Valuation Rule. The proposed rule would delete: (1) The definition of ''misconduct'' from § 1206.20; (2) the default provision from §§ 1206.105, 1206.144, 1206.254, and 1206.454, as well as references in other sections; and (3) the requirement that all contracts be signed by all parties to the contract from 30 CFR 1207.5, 1206.104(g)(1), 1206.143(g)(3), 1206.253(g)(1), and 1206.453(g)(1).

In the 2015 Proposed Valuation Rule and 2016 Valuation Rule, ONRR distinguished between the ''misconduct'' definition in the civil penalty regulations and the ''misconduct'' definition in the valuation regulations at § 1206.20. Industry stakeholders have argued that the ''misconduct'' definition in the valuation regulations is too broad and could be misapplied.

Under § 1210.30, ONRR requires lessees to ''submit accurate, complete, and timely information,'' which means that lessees are required to correct simple reporting errors when the lessee or ONRR discovers them—regardless of whether the errors constitute misconduct. ONRR therefore agrees that the new definition of misconduct is unduly burdensome and duplicative. As noted below, ONRR is requesting comments on further revisions to its rules to replace the usage of the term ''misconduct'' since the definition of misconduct may be eliminated in § 1206.20.

Like the ''misconduct'' definition, industry believes that ONRR could misapply the default provision in ways that undermine the other pillars of our regulatory scheme (which include, for example, basing allowances on reasonable actual costs, identifying where royalties are calculated, and looking to arm's-length transactions as the best indicator of value). While the purpose of the default provision was to provide a means for establishing royalty value when the most frequently used valuation methods are unavailable or unworkable, ONRR believes that the default provision is unnecessary considering successful historical practice without it. For years, ONRR successfully performed compliance activities and, where appropriate, exercised Secretarial discretion to establish royalty values absent a default provision. Given the recent direction in Executive Orders 13783 and 13795 to promote domestic energy production, ONRR believes that it unintendedly increased uncertainty due to the perception that ONRR might apply the default provision in place of accurate lessee reporting, thereby creating a regulatory burden for industry.

In the 2016 Valuation Rule, ONRR stated that to fully verify the correctness of royalty reports and payments, ONRR needs to see that all parties signed the contract. Then, in the 2017 Repeal Rule, ONRR provided 5 reasons why a contract that was not signed by all parties could be sufficient to determine compliance:

1. ''[U]nsigned, written agreements may be binding, legally enforceable contracts.''

2. The ''provision contradicted the definition of 'contract' in the rule itself, which defined 'contract' as any oral or writing agreement . . . that is enforceable by law.''

3. The preamble ''stated that ONRR could discount or ignore an arm's-length contract if the contract were not in writing and signed by all of the parties, which ran counter to ONRR's long-held position that arm's-length sales are the best indicator of market value.''

4. ''[T]he rule required the lessees' affiliates to have all of their contracts, contract revisions, and amendments reduced to writing and signed by all of the parties, despite the fact that the affiliates are not Federal or Indian lessees and the rule was not purporting to regulate them.''

5. ''[T]he rule burdened lessees and their affiliates with an unnecessary and potentially costly obligation to conform contracts to meet ONRR's specifications, which could increase the cost of production and delay the delivery of mineral resources.''

ONRR did not address how we might fulfill that statutory mandate without the signature requirement in the 2017 Repeal Rule because ONRR has fulfilled that mandate for decades without an additional requirement. If finalized as proposed, ONRR would evaluate a party's course of performance under all contracts—signed and unsigned—consistent with its historical practice.

ONRR proposes to eliminate the requirement that a lessee create, maintain, and provide contracts signed by all parties, but would keep the requirement that has existed since 1988 that contracts be in written form. The requirement that lessees place contracts in writing is found under 30 CFR 1207.5, 1206.104(g)(1), 1206.143(g)(3), 1206.253(g)(1), and 1206.453(g)(1).

Here, ONRR, in an effort to relieve certain regulatory burdens the 2016 Valuation Rule places on industry, is reevaluating the requirement for a lessee to maintain signed contracts. Without a requirement to maintain signed contracts, ONRR possesses broad authority to investigate and question the validity of any contract. For example, ONRR may choose to exercise that authority in situations where ONRR suspects that an arm's-length or non-arm's-length contract: (1) Fails to reflect actual performance, (2) shows a breach of the lessee's duty to market for the benefit of the lessor, or (3) shows lessee misconduct. Thus, ONRR estimates little, if any, impact on our methods for determining compliance. Moreover, ONRR recognizes that contracts may be valid and enforceable, as a matter of law, despite the absence of one or more signatures.

5. Citation to Legal Precedent With Valuation Determination Requests

ONRR proposes to eliminate the requirements under 30 CFR 1206.108(a)(5), 1206.148(a)(5), 1206.258(a)(5) and 1206.458(a)(5) for a lessee to include citations to legal precedents when requesting a valuation determination.

ONRR encourages a lessee to provide, along with the lessee's valuation request, any citations to precedent that it believes are persuasive. At the same time, ONRR is familiar with, and commonly a party to, matters that generate precedent for Federal oil and gas, Federal coal, and Indian coal royalty valuation. So, although citations might expedite the processing time for an industry request, it is not necessary to require industry to provide citations to precedent. Further, ONRR believes that it would be unproductive to attempt to enforce or litigate such a requirement, especially because a failure to include a citation to precedent may not, on its own, provide a sufficient reason to deny an otherwise valid request for a valuation determination. Finally, ONRR is reevaluating whether it inadvertently created an undue burden on industry by requiring lessees to provide legal precedents with valuation determination requests because that requirement might require a lessee to retain legal counsel instead of allowing a lessee's non-legal staff to more expeditiously communicate with ONRR regarding a valuation determination request.

6. Coal Valued as Electricity

ONRR proposes to amend 30 CFR part 1206 to remove the requirements under §§ 1206.252 (Federal coal) and 1206.452 (Indian coal) to value coal based on the first arm's-length sale as electricity. Instead, ONRR proposes to require a lessee to value that coal based on certain other arm's-length sales, or, where those sales do not exist, to request a valuation determination under 30 CFR 1206.258 (Federal coal) or 1206.458 (Indian coal). ONRR defended the coal valuation rules but, upon consideration of the parties' briefs and, after receiving the Court's ruling, it has determined that ONRR should revisit the coal rules to provide an alternative requirement that maintains the royalty value of coal using a less burdensome and controversial method. This would bring the ONRR's regulations in conformity with the Court's ruling in *Cloud Peak, supra,* and remove the burden and cost to ONRR and industry to obtain and validate the information.

7. The ''Coal Cooperative'' Definition

ONRR proposes to amend 30 CFR part 1206 to remove the ''coal cooperative'' definition under § 1206.20 and all other references thereto. ONRR is attempting to relieve concerns with the definition's applicability and meaning. While the Court, in *Cloud Peak,* did not find the coal cooperative definition to be arbitrary and capricious, the Court offered strong criticism of the definition. Accordingly, this amendment would harmonize the ONRR's rules with the Court's statements in *Cloud Peak, supra.*

8. Civil Penalties for Payment Violations

ONRR proposes to amend § 1241.70 to clarify that—for payment violations only—ONRR would consider the monetary impact of the entity's conduct when assessing a civil penalty. Section 1241.70(b) arguably created an ambiguity as to whether ONRR considers the unpaid, underpaid, or late-paid amounts when assessing a penalty for a payment violation under § 1241.50. Clarifying this ONRR civil penalty practice would support Executive Order 13892—Promoting the Rule of Law Through Transparency and Fairness in Civil Administrative Enforcement and Adjudication.

9. Aggravating and Mitigating Circumstances

ONRR proposes to amend § 1241.70 to clarify that ONRR may consider aggravating and mitigating circumstances to determine an appropriate penalty. ONRR considers aggravating and mitigating circumstances on a case-by-case basis to increase or decrease the penalty amount in a Failure to Correct Civil Penalty Notice (FCCP) or Immediate Liability Civil Penalty Notice (ILCP). Potential aggravating circumstances may include, but are not limited to, when the violation may also be a criminal act, when the violation occurs because a violator calculated the cost of compliance is more than the cost of a penalty, or when a violator has no history of noncompliance for the violation at hand but has an extensive history of noncompliance for other violation types. Mitigating circumstances are generally conditions where a lessee has limited control including, but not limited to, operational impacts resulting from the unexpected illness or death of an employee, natural disasters, pandemics, acts of terrorism, civil unrest, or armed conflict or delays caused by government action or inaction, including as a result of a government shutdown or ONRR-system downtime. Consistent with the general approach of Executive Order 13924 ''Regulatory Relief to Support Economic Recovery'' and Executive Order 13892 ''Promoting the Rule of Law Through Transparency and Fairness in Civil Administrative Enforcement and Adjudication,'' the failure of a lessee to conform to formal or informal agency guidance does not, in itself, establish a violation, while good faith efforts to comply with formal or informal agency guidance constitute mitigating circumstances and may serve as a rationale to decline issuing enforcement penalties entirely.

10. Administrative Law Judges May Not Withdraw Stay of Civil Penalty Accruals

ONRR proposes to amend § 1241.11 to return to its historical practice of guaranteeing an appellant the benefit of a stay of the accrual of a civil penalty during an appeal if granted by the Department's administrative law judge (''ALJ''). Specifically, the proposed rule would remove § 1241.11(b)(5), which states: ''Notwithstanding paragraphs (b)(1), (2), (3), and (4) of this section, if the ALJ determines that your defense to a Notice is frivolous, and a civil penalty is owed, you will forfeit the benefit of the stay, and penalties will be calculated as if no stay had been granted.''

When ONRR adopted the 2016 Civil Penalty Rule, § 1241.11(b)(5) was added. When API challenged the 2016 Civil Penalty Rule, the challenge was rejected except as to § 1241.11(b)(5). *API,* 366 F. Supp. 3d at 1310. Because § 1241.11(b)(5) was invalidated through a judicial proceeding and ONRR is not pursuing a review of this portion of the Court's ruling in API's ongoing appeal, ONRR proposes to remove the paragraph from the 2016 Civil Penalty Rule.

E. Economic Analysis

ONRR summarized the estimated changes to royalties and regulatory costs the proposed rule may have on potentially affected groups, including industry, the Federal Government, and State and local governments. A number of the proposed Federal oil and gas amendments would result in decreased royalty collections.

ONRR notes that changes to royalties are transfers that are distinguishable from regulatory costs (or cost savings). The estimated changes in royalties assessed will change both the private cost to the lessee and the amount of revenue collected by the Federal government and disbursed to State and local governments. The net impact of the proposed amendments is an estimated $42.1 million annual decrease in royalty collections. This represents a decrease of less than one-half of one percent of the total Federal oil and gas royalties ONRR collected in 2018. However, the financial impact, as evident in the total annual estimate reflected above, does impact the royalty disbursements for the Treasury and States who are stakeholders and recipients of ONRR's distributions.

Increased domestic energy production protects the United States from supply disruptions abroad and may also lead to an overall increase in royalty collections. Further, an industry more focused on domestic capital expenditures may create jobs and increase cash circulation in the United States' economy. As such, ONRR recognizes that the United States benefits from domestic energy production beyond the production's royalty value. In the instances where this rule proposes to alter royalties, ONRR is particularly interested in public comments on whether, and to what extent, the proposed amendments would impact domestic energy exploration and energy production, create economic opportunity, or otherwise provide justification to alter—or not—those transfer payments between the United States and its lessees.

ONRR also estimates that the Federal oil and gas industry would experience increased annual administrative costs of $2.58 million if ONRR adopts the entirety of this rule as proposed. As discussed below, this is the net impact of various cost increasing and cost saving proposals.

ONRR estimates that the proposed rule would have no economic impact on Federal and Indian coal. Please note that, unless otherwise indicated, numbers in the tables in this section are rounded to the nearest thousand, and that the totals may not match due to rounding.

1. Federal Oil and Gas

i. Industry

This table shows the change in royalties by rule provision for the first year and each year thereafter:

SUMMARY OF PROPOSED CHANGES TO OIL & GAS ROYALTIES PAID (ANNUAL)

Rule provision	Net change in royalties paid by lessees
Index-Based Valuation Option Extended to Gas Dispositions	$5,620,000
Index-Based Valuation Option Extended to NGL Dispositions	21,141,000
High to Midpoint Index Price for Non-Arm's-Length Gas Dispositions	(4,488,000)
Transportation Deduction Non-Arm's-Length Index-Based Valuation Option	(7,121,000)
Gas Transportation Allowances	(279,000)
Oil Transportation Allowances	(11,000)
Gas Processing Allowances	(9,942,000)
Extraordinary Processing Allowances	(11,131,000)
Deepwater Policy	(35,900,000)
Total	(42,111,000)

ONRR estimates the administrative cost savings from optional use of the index-based valuation method for gas and NGL sales, and administrative costs from the transportation allowance for certain gathering activities covered by the Deepwater Policy. These administrative costs to industry total approximately $2.58 million annually.

SUMMARY OF ANNUAL ADMINISTRATIVE IMPACTS TO INDUSTRY

Rule provision	Cost (cost savings)
Administrative Benefit for Index-Based Valuation Option for Gas & NGLs	($1,356,000)
Administrative Cost for Deepwater Policy	3,936,000
Total	2,580,000

ONRR also estimates industry will incur a one-time administrative cost savings of $4.5 million from the simplification of reporting process and transportation allowances associated with the optional use of the index-based valuation method. These costs are only calculated one time and then used to break out allowed from disallowed costs in reported transportation and processing allowances.

ONE-TIME ADMINISTRATIVE IMPACTS TO INDUSTRY

Rule provision	Cost savings
Administrative Cost-savings in lieu of Unbundling related to Index-Based Valuation Option for Gas & NGLs	$4,520,000

To perform this economic analysis, ONRR reviewed royalty data for Federal oil, condensate, residue gas, unprocessed gas, fuel gas, gas lost—flared or vented, carbon dioxide, sulfur, coalbed methane, and natural gas products (product codes 03, 04, 15, 16, 17, 19, 39, 07, 01, 02, 61, 62, 63, 64, and 65) from the last five calendar years, 2014–2018. ONRR believes that the vast majority of that reporting was made in compliance with the rules in place prior to the 2016 Valuation Rule. ONRR used five calendar years of royalty data because this longer time period helps smooth data to reduce volatility caused by fluctuations in commodity pricing and volume swings. ONRR used these data without adjusting for previous rulemakings because at the time of this analysis, a significant number of lessees and operators had not yet complied with the 2016 Valuation Rule's provisions due to its implementation delays, including the 2017 Repeal Rule, the subsequent 2019 Vacatur, and ONRR's two dear reporter letters providing industry with additional time to come into compliance with the 2016 Valuation following its reinstatement. ONRR adjusted the historical data in this analysis to 2018 dollars using the Consumer Price Index (all items in U.S. city average, all urban consumers) published by the Bureau of Labor Statistics (BLS). Based on ONRR's auditing experience, some companies aggregate their volumes (reported in thousand cubic feet (Mcf) and in a metric of energy content—one million British thermal units (MMBtu) for natural gas) in pools, and then sell the natural gas under multiple contracts. Lessees report those sales and dispositions using the ''POOL'' sales type code. Only a small portion of gas sales were non-arm's-length. Thus, ONRR used estimates of 10 percent of the POOL volumes in the economic analysis of non-arm's-length dispositions and 90 percent of the POOL volumes in the economic analysis of arm's-length dispositions. ONRR requests comments specific to how it could more accurately estimate the allocation between arm's-length and non-arm's-length sales.

Change in Royalty 1: Using Index-Based Valuation Option to Value Federal Unprocessed Gas, Residue Gas, Fuel Gas, and Coalbed Methane

To estimate the royalty impact of the option to pay royalties using index-based valuation, ONRR reviewed the reported royalty data for all gas sales except for non-arm's-length (discussed below), future valuation agreements, and percentage of proceeds sales. ONRR also adjusted the POOL sales down to 90 percent (as described above), which were spread across 10 major geographic areas with active index prices. The 10 areas account for over 95 percent of all Federal gas produced. ONRR assumes the remaining five percent of Federal gas lessees will not likely elect the index-based method as areas outside of major producing basins may have infrastructure limitations or limited access to index pricing. The 10 geographic areas are:

Offshore Gulf of Mexico
Big Horn Basin
Green River Basin
Permian Basin
Piceance Basin
Powder River Basin
San Juan Basin
Uinta Basin
Williston Basin
Wind River Basin

To calculate the estimated impact, ONRR:

(1) Identified the monthly bidweek price index, published by *Platts Inside FERC,* applicable to each area—Northwest Pipeline Rockies for Green River, Piceance and Uinta basins; El Paso San Juan for San Juan basin; Colorado Interstate Gas for Big Horn, Powder River, Williston, and Wind River basins; El Paso Permian for Permian basin; and Henry Hub for the Gulf of Mexico. ONRR determined price index applicability based on proximity to the producing area and the frequency by which ONRR's audit and compliance staff verify these index prices in sales contracts. ONRR is aware that not all sales in an area are based off these indices and requests further comment to improve this analysis.

(2) Subtracted the transportation deduction as modified by the proposed rule (detailed in the transportation section below) from the midpoint index price identified in step (1).

(3) Multiplied the royalty volume by the index price identified per region, less the transportation deduction calculated in step (2).

(4) Totaled the reported royalties less allowances reported on the monthly royalty report (form ONRR–2014) and the estimated royalties based on the index-based valuation option calculated in step (3).

(5) Calculated the annual average of reported royalties and estimated index-based royalties calculated in step (4) by dividing by five (number of years in the analysis).

(6) Subtracted the difference between the totals calculated in step (5).

ONRR anticipates that some lessees will choose to report to ONRR using this simpler method, saving administrative costs (described in detail below in Cost Savings 1 and Cost Savings 2, while other lessees will continue to calculate and deduct the actual costs they incur. ONRR cannot accurately estimate how many lessees will elect to use the index valuation method since many factors that are currently unquantifiable will drive a lessee's decision. For the purposes of this analysis, ONRR assumed that half of lessees would choose the alternative index-based valuation method to value dispositions eligible for the election. ONRR invites public comment on this assumption, and on other methods ONRR could use to more accurately estimate the economic impact of this election. ONRR's assumption of a 50 percent reduction is an attempt to simplify the myriad factors such as, simpler accounting methods for industry, company-specific break-even analysis, and simplified allowance unbundling administrative calculations. ONRR also broke out the Gulf of Mexico from the other onshore basins listed above because it accounts for approximately 30 percent of the total Federal gas sales used in this analysis, as well as having different complexities related to offshore gas production, when compared to onshore areas.

ONRR estimates that this change will increase annual royalty payments by approximately $5.3 million. This estimate represents an average increase of approximately one percent, or $0.04 per MMBtu, based on an annualized royalty volume of 296,440,024 MMBtu. ONRR chose not to include POP sales in the above methodology because the sales are reported inclusive of the NGL value and net of transportation and processing costs. To try to account for the change in value associated with POP contracts, ONRR applied the $0.04 per MMBtu calculated above to the annualized royalty volume for APOP sales of 158,772,452 MMBtu. The total estimated annual average impact is a $5.6 million increase in royalties. ONRR recognizes that it is not accounting for the value of APOP NGLs, however ONRR does not have a reasonable method to break out those components from the available data and would welcome comment on this matter.

ANNUAL NET CHANGE IN ROYALTIES PAID USING INDEX OPTION FOR GAS DISPOSITIONS

	Gulf of Mexico	Onshore basins	Total
Annualized Reported Royalties	$235,065,000	$541,124,000	$776,189,000
Royalties Estimated using Index-Based Valuation Option	250,183,000	536,564,000	786,747,000
Difference	15,118,000	(4,560,000)	10,558,000
Change per MMBtu	0.18	(0.02)	0.04
% Change	6	(1)	1
Annualized POP Royalties using Index-Based Valuation Option			(681,768)
50% of lessees choose this option			5,620,000

Change in Royalties 2: Using the Index-Based Valuation Option To Value Sales of Federal NGLs

Similar to the changes to Federal unprocessed gas, residue gas, pipeline fuel, and coalbed methane, a lessee will have the option to pay royalties on Federal NGLs using an index-based value less a theoretical processing allowance and be allowed an adjustment for transportation costs and fractionation costs, which account for the prices realized at the various NGL hubs. ONRR used the same 2014–2018 calendar years for all NGL sales except for non-arm's-length and future valuation agreements. ONRR also adjusted the POOL sales to 10 percent (as described above). These sales were spread across the same 10 major geographic areas with active index prices for this analysis. To calculate the estimated impact, ONRR:

(1) Identified the *Platts Oilgram Price Report Price Average Supplement (Platts Conway) or OPIS LP Gas Spot Prices Monthly (OPIS Mont Belvieu)* for published monthly midpoint NGL prices per component applicable to each area— Platts Conway for Williston and Wind River basins; and OPIS Mont Belvieu non-TET for the Gulf of Mexico, Big Horn, Green River, Permian, Piceance, Powder River, San Juan, and Uinta basins. In ONRR's audit experience, OPIS' prices are used to value NGLs in contracts more frequently at Mont Belvieu, and Platts' prices are used more frequently at Conway.

(2) Calculated an NGL basket price (a weighted average price to group the individual NGL components to a weighted price), which were compared to the imputed price from the monthly royalty report. The baskets illustrate the difference in the gas composition between Conway, Kansas and Mont Belvieu, Texas. The NGL basket hydrocarbon allocations are:

Platts Conway Basket	OPIS Mont Belvieu Basket
Ethane-propane (EP mix) 40%	Ethane 42%
Propane 28%	Non-TET Propane 28%
Isobutane 10%	Non-TET Isobutane 6%
Normal Butane 7%	Normal Butane 11%
Natural Gasoline 15%	Natural Gasoline 13%

(3) Subtracted the current theoretical allowance for processing deductions, as well as fractionation costs and transportation costs referenced in the current regulations and published online at *https://www.onrr.gov*, as shown in the table below from the NGL basket price calculated in step (2):

NGL DEDUCTION

[$/gal]

	Gulf of Mexico	New Mexico	Other areas
Processing	$0.10	$0.15	$0.15
Transportation and Fractionation	0.05	0.07	0.12
Total *(/gal)*	0.15	0.22	0.27

(4) Multiplied the royalty volume by the index price identified for each region, less the NGL deduction calculated in step (3).

(5) Totaled the royalty value less allowances reported on the monthly royalty report, and the estimated royalties based off the index-based valuation option calculated in step (4).

(6) Calculated the annual average of reported royalties and estimated index-based royalties calculated in step (5) by dividing by five (number of years in this analysis).

(7) Subtracted the difference between the totals calculated in step (6).

Because ONRR assumed that 50 percent of lessees would choose this option for eligible dispositions, ONRR reduced the total estimate by 50 percent in the following table, and ONRR invites public comments on this assumption and any other method available to more accurately quantify the economic impact of this election. ONRR estimates that this change will increase annual royalty payments by approximately

$21.1 million. This estimate represents an average increase of approximately 17 percent or $0.0894 per gallon, based on an annualized royalty volume of 475,257,250 gallons.

ANNUAL NET CHANGE IN ROYALTIES PAID USING INDEX OPTION FOR NGL SALES

	Gulf of Mexico	New Mexico	Other areas	Total
Annualized Reported Royalties	$74,438,000	$67,637,000	$70,072,000	$212,147,000
Royalties Estimated using Index-Based Valuation Option	77,068,000	66,397,000	110,962,000	254,428,000
Difference	2,630,000	(1,240,000)	40,891,000	42,281,000
Change per gallon	0.0174	(0.0081)	0.2439	0.0894
% Change	3	(2)	37	17
50% of lessees choose this option				21,141,000

Change in Royalties 3: Using the Average Index Price Versus the Highest Published Index Price to Value Non-Arm's-Length Federal Unprocessed Gas, Residue Gas, Coalbed Methane, and NGLs

As noted above, index-based valuation will change from using the *highest* published price for a specific index-pricing point to using the *average* published bidweek price for the index-pricing point. To estimate the royalty impact of this change to the index-based valuation option, ONRR used reported royalty data using non-arm's-length (''NARM'') sales and 10 percent of the POOL sales type codes based on the assumption above in the same 10 major geographic areas with active index-pricing points, also listed above.

To calculate the estimated impact, ONRR:

(1) Identified the *Platts Inside FERC* published monthly midpoint and high prices for the index applicable to each area—Northwest Pipeline Rockies for Green River, Piceance and Uinta basins; El Paso San Juan for San Juan basin; Colorado Interstate Gas for Big Horn, Powder River, Williston, and Wind River basins; El Paso Permian for Permian basin; and Henry Hub for the Gulf of Mexico.

(2) Multiplied the royalty volume by the published index prices identified for each region.

(3) Totaled the estimated royalties using the published index prices calculated in step (2).

(4) Calculated the annual average index-based royalties for both the high and volume-weighted-average prices calculated in step (3) by dividing by five (number of years in this analysis).

(5) Subtracted the difference between the totals calculated in step (4).

Because ONRR assumes that 50 percent of lessees would choose this option, ONRR reduced the total estimate by 50 percent in the following table, but ONRR invites public comment on this assumption and any other method available to more accurately quantify the economic impact. ONRR estimates that the result of this change is a decrease in annual royalty payments of approximately $4.5 million. This estimate represents an average decrease of approximately three percent or nine cents ($0.09) per MMBtu, based on an annualized royalty volume of 93,301,478 MMBtu (for NARM and 10 percent POOL reported sales type codes).

ANNUAL CHANGE IN ROYALTIES PAID DUE TO HIGH TO MIDPOINT MODIFICATION FOR NON-ARM'S-LENGTH SALES OF NATURAL GAS

	Gulf of Mexico	Onshore basins	Total
Royalties Estimated Using High Index Price	$107,736,000	$198,170,000	$305,907,000
Royalties Estimated Using Published Average Bidweek Price	107,448,000	189,483,000	296,931,000
Difference	(288,000)	(8,687,000)	(8,975,000)
Change per MMBtu	(0.01)	(0.14)	(0.10)
% Change	0	(5)	(3)
50% of lessees choose this option			(4,488,000)

NARM and 10% of POOL Sales Type Codes.

Change in Royalties 4: Modifying the Index-Based Valuation Option Transportation Deduction Used to Value Non-Arm's-Length Federal Unprocessed Gas, Residue Gas, Coalbed Methane, and NGLs

ONRR chose to update the transportation deductions applicable to non-arm's-length index-based valuation to reflect changes in industry transportation contracts terms and more recent allowance data reported to ONRR. To estimate the royalty impact of the modification to the transportation deduction, ONRR used reported royalty data using NARM and 10 percent of the POOL sales type codes from the same 10 major geographic areas with active index-pricing points listed above.

To calculate the estimated impact, ONRR:

(1) Identified appropriate areas using *Platts Inside FERC* index prices (see list above).

(2) Calculated the transportation deduction as published in the current regulations and the deduction outlined in the table below for each area identified in step (1).

TRANSPORTATION DEDUCTION OF INDEX-BASED VALUATION OPTION FOR GAS ($/MMBTU)

Element	Current regulations	2019 proposed rule
Gulf of Mexico %	5	10
Gulf of Mexico Low Limit	$0.10	$0.10
Gulf of Mexico High Limit	0.30	0.40
Other Areas %	10	15
Other Areas Low Limit	0.10	0.10
Other Areas High Limit	0.30	0.50

(3) Multiplied the royalty volume by the applicable transportation deduction identified for each area calculated in step (2).

(4) Totaled the estimated royalty impact based off both transportation deductions calculated in step (3).

(5) Calculated the annual average royalty impact for both methods calculated in step (4) by dividing by five (number of years in this analysis).

(6) Subtracted the difference between the totals calculated in step (5).

Because ONRR estimates that 50 percent of lessees will choose this option, ONRR reduced the total estimate by 50 percent. Please note that the figures in the table below represent the difference between the current transportation adjustment percentage and the percentage under the index-based valuation option. ONRR estimates the change will result in a decrease in annual royalty payments of approximately $7.1 million. This estimate represents an average decrease of approximately 65 percent or 15 cents per MMBtu, based on an annualized royalty volume of 93,301,478 MMBtu (for NARM and 10 percent POOL reported sales type codes).

ANNUAL CHANGE IN ROYALTIES DUE TO TRANSPORTATION DEDUCTION MODIFICATION FOR NON-ARM'S-LENGTH SALES OF NATURAL GAS

	Gulf of Mexico	Other areas	Total
Current Regulations Transport Deduction	$5,387,000	$16,375,000	$21,762,000
Estimate using new Transport Deduction	10,346,000	25,659,000	36,005,000
Difference	4,959,000	9,284,000	14,243,000
Change per MMBtu	0.15	0.15	0.15
50% of lessees choose this option			7,121,000
Net change in royalties as a result			(7,121,000)

Change in Royalties 4: Transportation Allowances in Excess of 50 Percent of the Royalty Value Prior to Allowances for Federal Gas

In certain scenarios, a lessee may incur costs to transport Federal gas at a cost that exceeds the regulatory limit of 50 percent of the gas's royalty value prior to allowances. The proposed rule provides a lessee the ability to request to exceed the 50 percent limit when the lessee's costs above 50 percent are reasonable, actual, and necessary. To estimate the change in royalties associated with the proposed amendment, ONRR first identified all gas transportation allowances reported on the monthly royalty reports exceeding the 50 percent limit for calendar years 2014–2018. Next, ONRR calculated the transportation allowance claimed for each royalty line compared to what the transportation allowance would have been at the 50 percent limit. ONRR then calculated annual totals and averaged them over 5 years. The result is an annual decrease in royalties paid by industry of approximately $279,000 per year.

Change in Royalties 5: Transportation Allowances in Excess of 50 Percent of the Royalty Value Prior to Allowances for Federal Oil

As described in the section above, a lessee may incur costs to transport Federal oil that exceed the regulatory limit of 50 percent of the oil's royalty value prior to allowances. This proposed rule would provide a lessee the ability to request to exceed that limit when the lessee's actual costs are reasonable, actual, and necessary. To estimate the change in royalties associated with this change, ONRR first identified all oil transportation allowances reported on the monthly royalty report that exceeded the 50 percent limit for calendar years 2014–2018. As above, ONRR calculated the transportation allowance claimed for each royalty line compared to what the transportation allowance would have been at the 50 percent limit. ONRR then calculated annual totals and averaged them over five years. The result was an annual decrease in royalties paid by industry of approximately $11,000 per year.

Change in Royalties 6: Processing Allowances in Excess of 66⅔ Percent of the Royalty Value of Federal NGLs Prior to Allowances

As with transportation allowances, a lessee may incur costs required to process gas that exceed the regulatory limit of 66⅔ percent of the royalty value of the NGLs prior to allowances. The proposed rule provides a lessee the ability to request to exceed that limit when the lessee's costs above 66⅔ percent are reasonable, actual, and necessary. To estimate the change in royalties associated with this change, ONRR completed two separate calculations.

First ONRR identified all NGL processing allowances reported on the monthly royalty report that exceeded the 66⅔ percent limit for calendar years 2014–2018. Next, ONRR calculated the processing allowance claimed for each royalty line compared to what the processing allowance would have been at the 66⅔ percent limit. ONRR then calculated annual totals and averaged them over five years. The result was an annual estimated decrease in royalties paid by approximately $135,000 per year.

ONRR also calculated and quantified the estimated impact for any allowances above the 66⅔ percent limit for percentage of proceeds (POP) contract sales. When POP sales are reported to ONRR, sales of gas are reported where the value of the unprocessed gas is based on a percentage of the proceeds the purchaser receives for the sales of the processed gas plus the gas plant products attributed to the lessee's production. Under the 2016 Valuation Rule, a lessee with a POP contract is limited to 66⅔ percent of the royalty value prior to allowances of the NGLs as a processing allowance even if its actual costs exceed this limit. This proposed rule provides a lessee the ability to request to exceed the 66⅔ percent limit for all processed gas contracts when the lessee's costs are reasonable, actual, and necessary. For example, a lessee with a 70 percent POP contract receives 70 percent of the value of the residue gas and 70 percent of the value of the NGLs. The 30 percent of each product that the lessee provides the processing plant in the past cannot, when combined, exceed a value equivalent to 100 percent of the NGLs' value. Under the proposed rule, the combined value of each product that a lessee gives up to the processing plant could, with approval, exceed two thirds of the NGLs' value.

Prior to the 2016 Valuation Rule, a lessee reported POP contracts to ONRR using a sales type code that showed whether it was an arm's-length (an APOP) or non-arm's-length (an NPOP) POP contract. Because lessees reported APOP sales as unprocessed gas, there are no reported processing allowances available for analysis, and ONRR cannot determine the breakout between residue gas and NGLs. Lessees report residue gas and NGLs separately for NPOPs. But NPOP volumes constitute only 0.04 percent of all the natural gas royalty volumes that lessees report to ONRR. ONRR deemed the NPOP volume to be too low to adequately assess the impact of this provision on both APOP and NPOP contracts. Thus, ONRR examined the onshore residue gas and NGL royalty data reported for calendar years 2014–2018 and assumed that lessees processed the gas and paid royalties as if they sold the residue gas and NGLs under a POP contract. First, ONRR averaged the total five-year residue gas and NGL royalty values and assumed, based on typical agreement percentage splits observed in compliance activities, that these royalties were subject to a 70-percent POP contract. ONRR's compliance activities indicate the typical POP contracts split is at a 70/30 percent weighting retained percent of proceeds and cost of processing. ONRR calculated 30 percent of both the value of residue gas and NGLs to approximate a theoretical 30-percent processing deduction and then compared the 30 percent total of residue gas and NGL values to 66⅔ percent of the NGL value (the maximum allowance under the current regulations). The table below summarizes the calculations, rounded to the nearest dollar:

POP CONTRACT ALLOWANCE THRESHOLD DETERMINATION

	5-year average royalty value prior to allowances	70% proceeds portion of POP contract	30% processing cost portion of POP contract
Residue Gas	$765,199,287	$535,639,501	$229,559,786
NGLs	274,631,986	192,242,391	82,389,596
Total	1,039,831,273	727,881,891	311,949,382
66⅔ % Limit	183,087,991	(274,631,986 × ⅔)	
Difference	128,861,391	($311,949,382 − $183,087,991)	

ONRR's analysis shows that, under the theoretical processing allowance and POP contract, 30 percent of residue gas and NGLs ($312 million) would exceed the 66⅔ cap ($183 million). ONRR estimates that this will reduce annual royalty payments by $9.8 million, which is a transfer from the Federal, State, and local governments to industry. ONRR determined this estimate by taking the royalty value exceeding the POP contract allowance ($128.9 million) and dividing it by the annual average non-POP volume (2,254,617,156 MMBtu) to calculate a per-MMBtu rate of $0.06. ONRR then applied the $0.06 rate to the POP contract total volume of 163,455,735 MMBtu to reach the $9.8 million estimate. In this analysis, ONRR assumed all processing costs associated with the 30 percent assumption were allowable.

ANNUAL CHANGE IN ROYALTIES FOR REQUESTS TO EXCEED ALLOWANCE THRESHOLD FOR POP CONTRACTS

Annualized MMBtu Volume	2,254,617,156	
Rate/MMBtu over limit	$0.06	($128,861,391/2,254,617,156)
Annualized POP MMBtu Volume	163,455,735	
Estimated Change in Royalties	($9,807,000)	($.06 × 163,455,735)

The total impact of both scenarios to allow processing allowances in excess of 66⅔ percent results in an annual estimated decrease in royalties of approximately $9.8 million.

Change in Royalties 7: Extraordinary Cost Gas Processing Allowances for Federal Gas

The proposed rule would allow a lessee to request an extraordinary processing cost allowance. Using the approvals ONRR granted prior to the 2016 Valuation Rule, we identified the 127 leases claiming an extraordinary processing allowance for residue gas, sulfur, and CO_2 for calendar years 2014–2018. The total processing costs are reported across all three products for these unique situations. For these leases, we retrieved all Form ONRR–2014 lines with a processing allowance reported by lessees. For CO_2 and sulfur produced from these leases, ONRR then calculated the annual average processing allowances which exceeded the 66⅔ percent limit and found that only two years in the analysis showed that the total allowances exceeded the 66⅔-percent limit. Under these unique exceptions, the processing allowances are also reported against residue gas, so we also added the average annual processing allowances taken for those same leases for residue gas. Based on these calculations, ONRR estimates this change will result in a decrease in annual royalty payments of approximately $11.1 million.

ESTIMATED ANNUAL CHANGE IN ROYALTIES PAID

Annual Average Sulfur allowances in excess of 66⅔%	($348,000)
Annual Average Residue Gas Allowance	(10,783,000)
Estimated Impact on Royalties	(11,131,000)

Change in Royalties 8: Transportation Allowances for Deepwater Gathering for Federal Oil and Gas

The Deepwater Policy was in effect from 1999 until January 1, 2017 (the 2016 Valuation Rule's effective date). Under the Deepwater Policy, ONRR allowed a lessee to treat certain expenses for subsea gathering as transportation expenses and to deduct those costs from its royalty payments. The 2016 Valuation Rule rescinded the Deepwater Policy. To analyze the impact to industry of allowing the gathering costs to be treated as deductible transportation costs, ONRR used data from the Bureau of Safety and Environmental Enforcement's (BSEE's) Technical Information Management System database to identify 113 current subsea pipeline segments, and potentially 169 eligible leases, which may qualify for an allowance under the Deepwater Policy. ONRR assumed that all segments were similar (in other words, no adjustments were made to account for the size, length, or type of pipeline) and considered only the pipeline segments that were in active status and supporting leases in producing status. To determine the range (shown in the tables at the end of this section as low, mid, and high estimates) of changes to royalties, ONRR estimates a 15 percent error rate in the identification of the 113 eligible pipeline segments. This resulted in a range of 96 to 130 eligible pipeline segments. ONRR's audit data is available for 13 subsea gathering segments serving 15 leases covering time periods from 1999 through 2010. ONRR used the data to determine an average initial capital investment in the pipeline segments. ONRR used the initial capital investment total to calculate depreciation and a return on undepreciated capital investment (also known as the return on investment or ROI) for eligible pipeline segments and calculated depreciation using a 20-year straight-line depreciation schedule.

ONRR calculated return on investment using the average BBB Bond rate (the BBB Bond rating is a credit rating used by the Standard & Poor's credit agency to signify a certain risk level of long-term bonds and other investments) for January 2018. ONRR based the calculations for depreciation and ROI on the first year a pipeline was in service. From the same audit information, ONRR calculated an average annual operating and maintenance (O&M) cost. ONRR increased the O&M cost by 12 percent to represent overhead expenses. ONRR then decreased the total annual O&M cost per pipeline segment by nine percent because, on average, nine percent of wellhead production volume is water. Water is not royalty bearing, and a lessee may not take a deduction against non-royalty-bearing fluids. Finally, ONRR used an average royalty rate of 14 percent, which is the volume-weighted-average royalty rate for the non-Section 6 leases in the Gulf of Mexico. Based on these calculations, the average annual allowance per pipeline segment is approximately $256,000. This represents the estimated amount per pipeline segment that ONRR would allow a lessee to take as a transportation allowance based on the Deepwater Policy. To calculate a range for the total cost, we multiplied the average annual allowance by the low (96), mid (113), and high (130) number of eligible segments. The low, mid, and high annual allowance estimates are $35 million, $41.1 million, and $47.3 million, respectively.

Of the eligible leases, 68 of 169, or about 40 percent, will qualify for a deduction under the proposed amendment. But due to varying lease terms, royalty relief programs, price thresholds, volume thresholds, and other factors, ONRR estimated that half of the 68, or 32, leases eligible for royalty relief (20 percent of 169) have received royalty relief. Thus, we decreased the low, mid, and high annual cost-to-industry estimates by 20 percent. The table below shows this section's estimated royalty impact.

ANNUAL ESTIMATED CHANGE IN ROYALTIES ALLOWING DEEPWATER GATHERING

	Low	Mid	High
Royalty Impact	($30,500,000)	($35,900,000)	($41,300,000)

Cost 1 Transportation Allowances for Deepwater Gathering for Offshore Federal Oil and Gas

The proposed rule, by allowing transportation allowances for deepwater gathering systems, will result in an administrative cost to industry because it requires qualified lessees to monitor their costs and perform calculations. The cost to perform this calculation is significant because industry often hires outside consultants to calculate their subsea transportation allowances. ONRR estimates that each lessee with leases eligible for transportation allowances for deepwater gathering systems will allocate one full-time employee annually to perform the calculation. ONRR used data from the BLS to estimate the hourly cost for industry accountants in a metropolitan area [$42.39 mean hourly wage] with a multiplier of 1.4 for industry benefits to equal approximately $59.35 per hour [$42.39 × 1.4 = $59.35]. Using this fully-burdened labor cost per hour, ONRR estimates that the annual administrative cost to industry would be approximately $3.9 million.

ANNUAL ADMINISTRATIVE COST TO INDUSTRY TO CALCULATE DEEPWATER TRANSPORTATION

	Annual burden hours per company	Industry labor cost/hour	Companies reporting eligible leases	Estimated cost to industry
Deepwater Policy	2,080	$59.35	32	$3,936,000

Cost Savings 1: Administrative Cost Savings From Using Index-Based Valuation Option to Value Federal Unprocessed Gas, Residue Gas, Coalbed Methane, and NGLs

ONRR expects that industry will realize administrative-cost savings if they choose to use the index-based valuation option to value dispositions of Federal unprocessed gas, residue gas, coalbed methane, and NGLs. A lessee will have price certainty when calculating its royalties—saving time it currently spends on verifying gross proceeds. ONRR estimates that 50 percent of lessees will use the index-based valuation option. Further, ONRR estimates that it will shorten the time burden per line reported by 50 percent (to 1.5 minutes per electronic line submission and 3.5 minutes per manual line submission). As with Cost 1, ONRR used tables from the Bureau of Labor Statistics to estimate the fully-burdened hourly cost for an industry accountant in a metropolitan area working in oil and gas extraction. The industry labor cost factor for accountants would be approximately $59.35 per hour = $42.39 [mean hourly wage] × 1.4 [benefits cost factor]. Using a labor cost factor of $59.35 per hour, ONRR estimates the annual administrative cost savings to industry will be approximately $1.4 million.

ANNUAL ADMINISTRATIVE COST SAVINGS FOR INDUSTRY

	Time burden per line reported	Estimated lines reported using index option (50%)	Annual burden hours
Electronic Reporting (99%)	1.5 min	892,620	22,315
Manual Reporting (1%)	3.5 min	9,016	526
Industry Labor Cost/hour			$59.35
Total Benefit to Industry			1,356,000

Cost Savings 2: Administrative Cost Savings Using Index-Based Valuation Option to Value Residue Gas and NGLs Simplifying Processing and Transportation Cost Calculations

ONRR expects industry will realize an additional one-time administrative-cost savings if they choose to use the index-based valuation option to value dispositions of Federal residue gas and NGLs, as this method eliminates the need to unbundle and calculate specific cost allocations related to processing and transportation. These cost allocations, referred to as ''unbundling,'' are segregated portions of a transportation or processing expense or fee attributable to placing production in marketable condition. Industry would unbundle their applicable plants and transportation systems one time in the absence of this rule and then use those unbundled cost allocations for subsequent royalty calculations. Industry is responsible for calculating these costs, however ONRR has published and calculated a limited number of unbundling cost allocations. In ONRR's experience, it takes approximately 100 hours per gas plant. ONRR calculated the average number of gas plants reported per payor is 3.4, across a total of 448 payors reporting residue gas and NGLs, between 2014–2018. Using the BLS labor cost per hour of $59.35 (described above) and adjusting our assumption to 50 percent of lessees choosing the index-based option, we believe this results in a one-time cost savings to industry of $4.5 million dollars.

i. State and Local Governments

ONRR estimates that the States and certain local governments this rule impacts would receive an overall decrease in royalty share (which, in part, was a reason for California's and New Mexico's challenges to the 2017 Repeal Rule) based on the category the lease falls under, including offshore Outer Continental Shelf Lands Act section 8(g) leases (See 43 U.S.C. 1337(g)), Gulf of Mexico Energy Security Act leases (GOMESA) ((43 U.S.C 1337(g))), and onshore Federal lands. ONRR disburses royalties based on where the oil, gas, or coal was produced.

Except for Federal Alaskan production (where Alaska receives 90 percent of the distribution), Section 8(g) leases in the OCS, and qualified leases under GOMESA in the OCS (more information on distribution percentages at *https://revenuedata.doi.gov/how-it-works/gomesa/*), the following distribution table generally applies:

ONRR DISBURSEMENTS BY AREA

	Onshore %	Offshore %
Federal	51	95.2
State	49	4.8

Please visit *https://revenuedata.doi.gov/explore/#federal-disbursements* to find more information on ONRR's disbursements to any specific State or local government.

The next table in this section summarizes the State and local government royalty decreases.

ii. Indian Lessors

The provisions in the proposed rule are not expected to affect Indian lessors.

iii. Federal Government

The impact of the proposed rule to the Federal Government will be a net decrease in royalty collections. ONRR estimates the net yearly impact on the Federal Government (detailed in the next table of this section) would be a loss of $32,239,000 in royalties.

iv. Summary of Royalty Impacts and Costs to Industry, State and Local Governments, Indian Lessors, and the Federal Government

In the table below, ONRR presents the net change in royalties by rulemaking provision. Changes to royalties are neither costs nor benefits, but transfers. The estimated changes in royalties assessed will change both the private cost to the operator/lessee and the amount of revenue collected by the Federal government and the States.

ANNUAL ECONOMIC IMPACTS FOR INDUSTRY, THE FEDERAL GOVERNMENT, AND STATES

Rule provision	Net change in royalties	Federal proportion	State proportion
Index-Based Valuation Option Extended to Gas Dispositions	$5,620,000	$3,606,000	$2,014,000
Index-Based Valuation Option Extended to NGL Dispositions	21,141,000	14,468,000	6,673,000
High to Midpoint Index Price for Non-Arm's-Length Gas Dispositions	(4,488,000)	(2,880,000)	(1,608,000)
Transportation Deduction Non-Arm's-Length Index-Based Valuation Option	(7,121,000)	(4,569,000)	(2,552,000)
Gas Transportation Allowances	(279,000)	(179,000)	(100,000)
Oil Transportation Allowances	(11,000)	(9,000)	(2,000)
Gas Processing Allowances	(9,942,000)	(6,379,000)	(3,563,000)
Extraordinary Processing Allowance	(11,131,000)	(7,142,000)	(3,989,000)
Deepwater Policy	(35,900,000)	(29,155,000)	(6,745,000)
Total	(42,111,000)	(32,239,000)	(9,872,000)

Note: totals may not add due to rounding.

2. Federal and Indian Coal

ONRR estimates that there will be no economic impact in terms of royalties to ONRR, Tribes, Individual Indian mineral owners, States, or industry from the changes to coal valuation in this proposed rule. The changes outlined in this proposed rule should result in coal values for royalty purposes similar to those reported and paid to ONRR under the regulations in effect since 1989. Further, as of this writing, lessees have not submitted coal reporting under the 2016 Valuation Rule, so ONRR lacks data showing any changes resulting from implementation of the provisions of the 2016 Valuation Rule.

ONRR requests your comments on the economic impact of the changes listed below.

Change 1: Eliminate Reference to Default Provision Requirements for Federal Oil and Gas

ONRR proposed to remove the default provision from its regulations. In instances of misconduct, breach of a lessee's duty to market, or other situations where royalty value cannot be determined under the rules, ONRR will use statutory authority to determine Federal oil and gas royalty value under lease terms, FOGRMA, and other authorizing legislation in the same manner—as ONRR would have prior to adoption of the 2016 Valuation Rule. ONRR does not believe there is any overall royalty impact from removing the default provision.

Change 2: Eliminating the Use of Arm's-Length Electricity Sales to Value Non-Arm's-Length Dispositions of Federal Coal.

In the 2016 Valuation Rule, ONRR estimated no impacts to industry for this provision. Further, because lessees have not submitted reporting under the 2016 Valuation Rule, ONRR lacks data showing any changes that may have been attributable to this provision.

Change 3: Using the First Arm's- Length Sale to Value Non-Arm's-Length Sales of Indian Coal

ONRR did not estimate any impacts to industry for the proposed change from this provision. Currently, lessees of Indian coal sell their entire production at arm's length, so this proposed change would have no royalty impact on lessees or lessors of Indian coal.

Change 4: Eliminating the Sales of Electricity to Value Non-Arm's-Length Sales of Indian Coal

ONRR did not estimate any impacts to industry for the proposed change for this provision. Currently, lessees of Indian coal sell their entire production at arm's-length so this proposed change would have no royalty impact on lessees or lessors of Indian coal.

Change 5: Using First Arm's-Length Sale to Value Sales of Indian Coal Between Parties That Lack Opposing Economic Interests.

At the present time, all producers of Indian coal sell the produced coal under arm's-length transactions. Accordingly, ONRR does not anticipate any impact to royalty collections from the proposed change.

Change 6: Elimination of the Default Provision to Value Federal Oil, Gas, and Coal and Indian Coal

ONRR estimates that the royalty impact would be insignificant because the default provision established a reasonable value of production using market-based transaction data, which has always been, and continues to be, the basis for ONRR's royalty valuation rules.

F. Public Comments

1. Federal Oil and Gas

1. ONRR requests comments identifying the complexities industry could avoid if an index-based valuation option were available for arm's-length dispositions. Where it can be reasonably determined, ONRR also requests comments quantifying the burden savings that an arm's-length index-based valuation option would provide, in place of reporting such dispositions using gross proceeds.

2. ONRR requests comments specific to any unintentional burdens that the 2016 Valuation Rule may have created by providing the index-based valuation option to only the non-arm's-length dispositions for a lessee with both arm's-length and non-arm's-length dispositions.

3. ONRR also requests comments on whether the 2016 Valuation Rule's separate arm's-length and non-arm's-length valuation methods impacted lessee decision making on whether to use the index-based valuation method for non-arm's-length dispositions.

4. ONRR requests comments on alternatives that more closely match values under the index-based valuation

method to the gross proceeds accruing under arm's-length dispositions across all Federal oil and gas leases.

5. ONRR requests comments on alternatives that would allow a lessee and ONRR to establish a clear and consistent location to determine royalty value under the index-based valuation options.

6. ONRR is proposing to revise the transportation adjustment for the OCS in the Gulf of Mexico to 10 percent per MMBtu, but not less than 10 cents or more than 40 cents per MMBtu, and for all other areas to 15 percent, but not less than 10 cents or more than 50 cents per MMBtu. ONRR requests comments specific to whether the proposed change accomplishes its purpose to more accurately reflect current transportation costs. ONRR is also interested in comments that propose alternative methods for calculating the transportation adjustment in a timely matter, or that would avoid potentially iterative, controversial rulemakings to update the adjustment.

7. ONRR requests comments on the impacts of the 2016 Valuation Rule's hard caps and the associated changes proposed in this rule. Specifically, we are interested in any specific data commenters can provide regarding the hard cap's effect on specific operations or other lessee decision making and arguments that may be made for or against the proposed change.

8. ONRR is interested in receiving comments specific to how codifying the Deepwater Policy would impact energy production and exploration in the OCS now and in the future at depths of 200 meters or deeper; how it would impact revenues to Federal, State, and local governments; and feedback on any effects that could be anticipated on non-OCS domestic production.

9. ONRR requests comments on the following: (a) In what shallow water situations is the Deepwater Policy currently applicable? (b) In what shallow water situations would it be appropriate or inappropriate to apply the Deepwater Policy in the future? (c) What criteria are appropriate to evaluate when determining whether a shallow water lease with a subsea completion should qualify for the deduction of gathering costs as a transportation allowance? (d) Are there lessons to be learned by how other leasing entities (*e.g.,* State or private landowners) manage such transportation allowances?

10. ONRR requests comments on the following: (a) In what remote-area situations is it uneconomic or unfeasible for a lessee to locate separation, treatment, or royalty measurement functions on or near the lease? (b) What criteria should ONRR use to distinguish between traditional gathering, which generally occurs on or near the lease, and the movement of bulk production in remote areas across lease boundaries to a central separation, treatment, or royalty measurement facilities? (c) How should ONRR distinguish between allowed and disallowed movement in remote areas? (d) How should ONRR define ''remote area?'' (e) Is there a way for ONRR to develop a coherent policy that distinguishes between remote and non-remote areas in terms of allowing deduction of certain costs to move bulk production? (f) If so, what are the advantages and disadvantages of such an approach to lessees and to the government (as resource owner)?

11. ONRR requests comments on the following: (a) What terms ONRR could use in place of ''misconduct'' to describe a lessee's activities that would warrant ONRR establishing royalty value? (b) What specific criteria ONRR could apply to distinguish when a lessee engaged in ''misconduct'' or the term replacing ''misconduct'' from a lessee's mere clerical errors?

12. ONRR requests comments on the following: (a) What criteria could ONRR establish to provide lessees more clarity and certainty on when ONRR would establish royalty value in place of typical methods? (b) What factors and methods should ONRR consider when establishing reasonable royalty values?

13. Without a requirement to maintain signed contracts, ONRR possesses broad authority to investigate and question the validity of any contract. Therefore, ONRR requests comments specific to any additional burdens the 2016 Valuation Rule's signature requirement placed on lessees.

14. ONRR proposes to eliminate the requirements under §§ 1206.108(a)(5), 1206.148(a)(5), 1206.258(a)(5) and 1206.458(a)(5) for a lessee to include citations to legal precedents when requesting a valuation determination. ONRR requests comments on the burdens the legal precedent requirement placed on industry, and any comments related to the necessity of retaining the requirement.

15. ONRR requests comments on how the proposed rule may or may not fulfill its objective to implement Executive Orders and Secretarial Orders. Moreover, ONRR looks to receive feedback on whether, and to what extent, the proposed amendments would impact domestic energy exploration and energy production, create economic opportunity, or otherwise provide justification to alter—or not—transfer payments between the United States and its lessees in the form of royalties.

2. Federal and Indian Coal

1. ONRR is interested in receiving comments on alternatives that could be used to value non-arm's-length coal sales and enable a lessee to access the information needed to support royalty reporting while ensuring the Federal and Indian lessors obtain fair market value for the royalty share.

2. ONRR also seeks input on whether the rules should be amended to establish a minimum royalty value to protect the Federal or Indian lessor's royalty share when production's value decreases between a lease or mine and where the first arm's-length sale occurs. Commenters are also encouraged to offer suggestions on the methodology to use to establish a minimum royalty value.

3. ONRR requests your comments on other appropriate alternatives to simplify the method to determine royalty value for coal a lessee does not sell at arm's-length, before its consumption or other disposition as electricity.

4. ONRR requests your comments on the economic impact of the following: (a) Eliminating the use of arm's-length electricity sales to value non-arm's-length dispositions of federal coal. (b) Using the first arm's- length sale to value non-arm's-length sales of Indian coal. (c) Eliminating the sales of electricity to value non-arm's-length sales of Indian coal. (d) Using first arm's-length sale to value sales of Indian coal between parties that lack opposing economic interests. (e) Elimination of the default provision to value federal oil, gas, and coal and Indian coal.

3. Civil Penalties

1. ONRR proposes to amend § 1241.70 to clarify that, for payment violations only, ONRR would consider the consequence of the unpaid, underpaid, or late payment amount when assessing a civil penalty. ONRR requests comment on how this would impact lessees to which ONRR issues a civil penalty.

2. ONRR proposes to amend § 1241.70 to clarify that ONRR may consider aggravating and mitigating circumstances to increase or decrease a penalty. ONRR requests comment on how this would impact lessees subject to an ONRR-issued civil penalty. ONRR also seeks comment on what facts or situations it should consider to be aggravating and mitigating circumstances.

3. ONRR seeks comment on how removing § 1241.11(b)(5) would affect lessees issued a civil penalty.

4. Other Matters

ONRR requests comment on all other aspects of this proposed rule, including (for instance) whether the proposed regulatory definition of ''Affiliate'' is too broad or too narrow in any respect. Commenters should provide appropriate reasoning and factual support for all contentions.

G. Statutory and Regulatory Review

1. Regulatory Planning and Review (Executive Orders 12866 and 13563)

SUMMARY OF PROPOSED CHANGES TO OIL & GAS ROYALTIES PAID (ANNUAL)

Rule provision	Net change in royalties paid by lessees
Index-Based Valuation Option Extended to Gas Dispositions	$5,620,000
Index-Based Valuation Option Extended to NGL Dispositions	21,141,000
High to Midpoint Index Price for Non-Arm's-Length Gas Dispositions	(4,488,000)
Transportation Deduction Non-Arm's-Length Index-Based Valuation Option	(7,121,000)
Gas Transportation Allowances	(279,000)
Oil Transportation Allowances	(11,000)
Gas Processing Allowances	(9,942,000)
Extraordinary Processing Allowances	(11,131,000)
Deepwater Policy	(35,900,000)
Total	(42,111,000)

SUMMARY OF ANNUAL ADMINSTRATIVE IMPACTS TO INDUSTRY

Rule provision	Cost (cost savings)
Administrative Benefit for Index-Based Valuation Option for Gas & NGLs	($1,356,000)
Administrative Cost for Deepwater Policy	3,936,000
Total	2,580,000

ONE-TIME ADMINISTRATIVE IMPACTS TO INDUSTRY

Rule Provision	(Cost savings)
Administrative Cost-savings in lieu of Unbundling related to Index-Based Valuation Option for Gas & NGLs	($4,520,000)

Executive Order 12866 provides that the Office of Information and Regulatory Affairs (OIRA) of the Office of Management and Budget (OMB) will review all significant rulemaking. OIRA has determined that the proposed rule is significant.

Executive Order 13563 reaffirms the principles of Executive Order 12866, while calling for improvements in the nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. This executive order directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives. Executive Order 13563 emphasizes further that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas. We developed this rule in a manner consistent with these requirements.

2. Regulatory Flexibility Act

The Department of the Interior certifies that the proposed rule would not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). See above for the costs, benefits, and economic analysis.

For the changes to 30 CFR part 1206, this rule would affect lessees of Federal oil and gas leases. For the changes to 30 CFR part 1241, this rule could affect violators of obligations under Federal and Indian mineral leases. Federal and Indian mineral lessees are, generally, companies classified under the North American Industry Classification System (NAICS), as follows:

- Code 211111, which includes companies that extract crude petroleum and natural gas
- Code 212111, which includes companies that extract surface coal
- Code 212112, which includes companies that extract underground coal

For these NAICS code classifications, a small company is one with fewer than 500 employees. Approximately 1,920 different companies submit royalty and production reports from Federal oil and gas leases and other Federal mineral leases to ONRR each month. Of these, approximately 65 companies would be large businesses under the U.S. Small Business Administration definition, because they would have more than 500 employees. The Department estimates that the remaining 1,855 companies that this rule would affect are small businesses. In this context, ONRR defines company size for lessees as follows; large: Average annual royalties over $100 million, medium: $99–$10 million, and small: Less than $10 million.

As stated in the Summary of Royalty Impacts and Costs table, shown above, this rule would benefit industry through a cost savings of approximately $42 million per year. Small businesses account for about 8 percent of the royalties. Applying that percentage to industry costs, we estimate that the changes in the proposed rule would result in a cost savings to small-business lessees by a total of approximately $3.5 million per year, which shared between the 1,855 companies totals in an average $1,887 cost savings per company. The amount would vary for each company depending on the volume of production that the small business produces and sells each year.

In sum, we do not estimate that this rule would result in a significant economic impact on a substantial number of small entities because this rule does not impose new costs on the regulated industry anywhere where those entities would not have an opportunity to realize some cost savings. Each small entity would consider the provisions to decide whether it is economically advantageous to incur increases in administrative costs to achieve the cost savings the provision would provide. The rule would benefit affected small businesses a collective total of $3.5 million per year. Thus, an Initial Regulatory Flexibility Act Analysis is not required, and, accordingly, a Small Entity Compliance Guide is not required.

Your comments are important. The Small Business and Agriculture Regulatory Enforcement Ombudsman and ten Regional Fairness Boards receive comments from small businesses about Federal agency enforcement actions. The Ombudsman annually evaluates the enforcement activities and rates each agency's responsiveness to small business. If you wish to comment on ONRR's actions, call 1–(888) 734–3247. You may comment to the Small Business Administration without fear of retaliation. Allegations of discrimination/retaliation filed with the Small Business Administration would be investigated for appropriate action.

3. Small Business Regulatory Enforcement Fairness Act

The proposed rule is not a major rule under 5 U.S.C. 804(2), the Small Business Regulatory Enforcement Fairness Act. This rule:

a. Will not have an annual effect on the economy of $100 million or more. We estimate that the cumulative effect on all of industry will be a reduction in private cost of nearly $39.52 million per year, which is the sum of $42.1 million in decreased royalty payments and $2.58 million in additional costs due to increased administrative burdens. The net change in royalty payments is a transfer rather than a cost or cost savings. The Summary of Royalty Impacts and Costs table, as shown above, demonstrates that the cumulative economic impact on industry, State and local governments, and the Federal Government will be well below the $100 million threshold that the Federal Government uses to define a rule as having a significant impact on the economy.

b. Will not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions. See above.

c. Will not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of United States-based enterprises to compete with foreign-based enterprises. The proposed rule would benefit United States-based enterprises. We are the only agency that promulgates rules for royalty valuation on Federal oil and gas leases and Federal and Indian coal leases.

4. Unfunded Mandates Reform Act

The proposed rule would not impose an unfunded mandate on State, local, or Tribal governments, or the private sector of more than $100 million per year. This rule will not have a significant or unique effect on State, local, or Tribal governments, or the private sector. Therefore, we are not required to provide a statement containing the information that the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*) requires because this rule is not an unfunded mandate.

5. Takings (Executive Order 12630)

Under the criteria in section 2 of Executive Order 12630, the proposed rule would not have any significant takings implications. This rule would not impose conditions or limitations on the use of any private property. This rule would apply to the valuation of Federal oil and gas and Federal and Indian coal only. The proposed rule would only make minor technical changes to ONRR's civil penalty regulations that have no expected economic impact. The proposed rule would not require a takings implication assessment.

6. Federalism (Executive Order 13132)

Under the criteria in section 1 of Executive Order 13132, the proposed rule would not have sufficient Federalism implications to warrant the preparation of a Federalism summary impact statement. The management of Federal oil and gas is the responsibility of the Secretary of the Interior, and ONRR distributes all of the royalties that we collect under Federal oil and gas leases as specified in the relevant disbursement statutes. This rule will not impose administrative costs on States or local governments. This rule also will not substantially and directly affect the relationship between the Federal and State governments. Because this rule will not alter that relationship, it does not require a Federalism summary impact statement.

7. Civil Justice Reform (Executive Order 12988)

The proposed rule complies with the requirements of Executive Order 12988. Specifically, this rule:

a. Will meet the criteria of Section 3(a), which requires that we review all regulations to eliminate errors and ambiguity and write them to minimize litigation.

b. Will meet the criteria of Section 3(b)(2), which requires that we write all regulations in clear language using clear legal standards.

8. Consultation With Indian Tribal Governments (Executive Order 13175)

Under the criteria in Executive Order 13175, ONRR evaluated the proposed rule and determined that it will not substantially affect Federally recognized Indian tribes. The proposed rule only affects Federal, not Indian, oil and gas leases. For Indian coal leases, ONRR estimated that the proposed rule would not alter the royalty valuation of Indian coal.

9. Paperwork Reduction Act

The proposed rule:

(a) Will not contain any new information collection requirements.

(b) Will not require a submission to OMB under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*). See 5 CFR 1320.4(a)(2).

The proposed rule will leave intact the information collection requirements that OMB has already approved under OMB Control Numbers 1012–0004, 1012–0005, and 1012–0010.

10. National Environmental Policy Act

This rule does not constitute a major Federal action significantly affecting the quality of the human environment. ONRR is not required to provide a detailed statement under the National Environmental Policy Act of 1969 (NEPA) because this rule qualifies for a categorical exclusion under 43 CFR 46.210(c) and (i) and the Department of the Interior's Departmental Manual, part 516, section 15.4.D: ''(c) Routine financial transactions including such things as . . . audits, fees, bonds, and royalties . . . [and] (i) [p]olicies, directives, regulations, and guidelines . . . [t]hat are of an administrative, financial, legal, technical, or procedural nature.'' ONRR also determined that this rule is not involved in any of the extraordinary circumstances listed in 43 CFR 46.215 that require further analysis under NEPA. The changes resulting from the proposed amendments will have no consequence on the physical environment. The proposed rule does not alter, in any material way, natural resources exploration, production, or transportation.

11. Effects on the Energy Supply (Executive Order 13211)

The proposed rule is not a significant energy action under the definition in Executive Order 13211, and, therefore, does not require a statement of energy effects.

12. Clarity of This Regulation

Executive Orders 12866 (section 1(b)(12)), 12988 (section 3(b)(1)(B)), and 13563 (section 1(a)), and the Presidential Memorandum of June 1, 1998, require us to write all rules in plain language. This means that the rules we publish must use:

(a) Logical organization.

(b) Active voice to address readers directly.

(c) Clear language rather than jargon.

(d) Short sections and sentences.

(e) Lists and tables wherever possible.

If you feel that ONRR has not met these requirements, send your comments to *Dane.Templin@onrr.gov.* To better help ONRR understand your comments, please make your comments as specific as possible. For example, you should tell ONRR the numbers of the sections or paragraphs that you think were written unclearly, which sections or sentences are too long, the sections where you feel lists or tables would be useful.

13. Public Availability of Comments

ONRR will post all comments we receive, including a respondent's name and address. Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment, including your personal identifying information, may be made publicly available at any time. While you can ask, in your comment, that your personal identifying information be withheld from public view, ONRR cannot guarantee that we will be able to do so.

List of Subjects

30 CFR Part 1206

Coal, Continental shelf, Geothermal energy, Government contracts, Indians—lands, Mineral royalties, Oil and gas exploration, Public lands—mineral resources, Reporting and recordkeeping requirements

30 CFR Part 1241

Administrative practice and procedure, Coal, Indians—lands, Mineral royalties, Natural gas, Oil and gas exploration, Penalties, Public lands—mineral resources.

Kimbra G. Davis,

Director for Office of Natural Resources Revenue.

Authority and Issuance

For the reasons discussed in the preamble, the Office of Natural Resources Revenue proposes to amend 30 CFR parts 1206 and 1241 as set forth below:

PART 1206—PRODUCT VALUATION

■ 1. The authority citation for part 1206 continues to read as follows:

Authority: 5 U.S.C. 301 *et seq.,* 25 U.S.C. 396 *et seq.,* 396a *et seq.,* 2101 *et seq.;* 30 U.S.C. 181 *et seq.,* 351 *et seq.,* 1001 *et seq.,*1701 *et seq.;* 31 U.S.C. 9701; 43 U.S.C. 1301 *et seq.,*1331 *et seq.,* and 1801 *et seq.*

Subpart A—General Provisions and Definitions

■ 2. Revise § 1206.20 to read as follows:

§ 1206.20 What definitions apply to this part?

The following definitions apply to this part:

Ad valorem lease means a lease where the royalty due to the lessor is based upon a percentage of the amount or value of the coal.

Affiliate means a person who controls, is controlled by, or is under common control with another person. For the purposes of this subpart:

(1) Ownership or common ownership of more than 50 percent of the voting securities, or instruments of ownership or other forms of ownership, of another person constitutes control. Ownership of less than 10 percent constitutes a presumption of non-control that ONRR may rebut.

(2) If there is ownership or common ownership of 10 through 50 percent of the voting securities or instruments of ownership, or other forms of ownership, of another person, ONRR will consider each of the following factors to determine if there is control under the circumstances of a particular case:

(i) The extent to which there are common officers or directors

(ii) With respect to the voting securities, or instruments of ownership or other forms of ownership: The percentage of ownership or common ownership, the relative percentage of ownership or common ownership compared to the percentage(s) of ownership by other persons, if a person is the greatest single owner, or if there is an opposing voting bloc of greater ownership

(iii) Operation of a lease, plant, pipeline, or other facility

(iv) The extent of other owners' participation in operations and day-to-day management of a lease, plant, or other facility

(v) Other evidence of power to exercise control over or common control with another person

(3) Regardless of any percentage of ownership or common ownership, relatives, either by blood or marriage, are affiliates.

ANS means Alaska North Slope.

Area means a geographic region at least as large as the limits of an oil and/or gas field, in which oil and/or gas lease products have similar quality and economic characteristics. Area boundaries are not officially designated and the areas are not necessarily named.

Arm's-length-contract means a contract or agreement between independent persons who are not affiliates and who have opposing economic interests regarding that contract. To be considered arm's-length for any production month, a contract must satisfy this definition for that month, as well as when the contract was executed.

Audit means an examination, conducted under the generally accepted Governmental Auditing Standards, of royalty reporting and payment compliance activities of lessees, designees or other persons who pay royalties, rents, or bonuses on Federal leases or Indian leases.

BIA means the Bureau of Indian Affairs of the Department of the Interior.

BLM means the Bureau of Land Management of the Department of the Interior.

BOEM means the Bureau of Ocean Energy Management of the Department of the Interior.

BSEE means the Bureau of Safety and Environmental Enforcement of the Department of the Interior.

Coal means coal of all ranks from lignite through anthracite.

Coal washing means any treatment to remove impurities from coal. Coal washing may include, but is not limited to, operations, such as flotation, air, water, or heavy media separation; drying; and related handling (or combination thereof).

Compression means the process of raising the pressure of gas.

Condensate means liquid hydrocarbons (normally exceeding 40 degrees of API gravity) recovered at the surface without processing. Condensate is the mixture of liquid hydrocarbons resulting from condensation of petroleum hydrocarbons existing initially in a gaseous phase in an underground reservoir.

Constraint means a reduction in, or elimination of, gas flow, deliveries, or sales required by the delivery system.

Contract means any oral or written agreement, including amendments or revisions, between two or more persons, that is enforceable by law and that, with due consideration, creates an obligation.

Designee means the person whom the lessee designates to report and pay the lessee's royalties for a lease.

Exchange agreement means an agreement where one person agrees to deliver oil to another person at a specified location in exchange for oil deliveries at another location. Exchange agreements may or may not specify prices for the oil involved. They frequently specify dollar amounts reflecting location, quality, or other differentials. Exchange agreements include buy/sell agreements, which specify prices to be paid at each exchange point and may appear to be two separate sales within the same agreement. Examples of other types of exchange agreements include, but are not limited to, exchanges of produced oil for specific types of crude oil (such as West Texas Intermediate); exchanges of produced oil for other crude oil at other locations (Location Trades); exchanges of produced oil for other grades of oil (Grade Trades); and multi-party exchanges.

FERC means Federal Energy Regulatory Commission.

Field means a geographic region situated over one or more subsurface oil and gas reservoirs and encompassing at least the outermost boundaries of all oil and gas accumulations known within those reservoirs, vertically projected to the land surface. State oil and gas regulatory agencies usually name onshore fields and designate their official boundaries. BOEM names and designates boundaries of OCS fields.

Gas means any fluid, either combustible or non-combustible, hydrocarbon or non-hydrocarbon, which is extracted from a reservoir and which has neither independent shape nor volume, but tends to expand indefinitely. It is a substance that exists in a gaseous or rarefied state under standard temperature and pressure conditions.

Gas plant products means separate marketable elements, compounds, or mixtures, whether in liquid, gaseous, or solid form, resulting from processing gas, excluding residue gas.

Gathering means the movement of lease production to a central accumulation or treatment point on the lease, unit, or communitized area, or to a central accumulation or treatment point off of the lease, unit, or communitized area that BLM or BSEE approves for onshore and offshore leases, respectively. Excluded from this definition is the movement of bulk production from a wellhead to an offshore platform which may, for valuation purposes, be considered a function for which a Transportation Allowance is properly taken pursuant to § 1206.110(a)(1).

Geographic region means, for Federal gas, an area at least as large as the defined limits of an oil and or gas field in which oil and/or gas lease products have similar quality and economic characteristics.

Gross proceeds means the total monies and other consideration accruing for the disposition of any of the following:

(1) *Oil.* Gross proceeds also include, but are not limited to, the following examples:

(i) Payments for services such as dehydration, marketing, measurement, or gathering which the lessee must perform at no cost to the Federal Government

(ii) The value of services, such as salt water disposal, that the producer normally performs but that the buyer performs on the producer's behalf

(iii) Reimbursements for harboring or terminalling fees, royalties, and any other reimbursements

(iv) Tax reimbursements, even though the Federal royalty interest may be exempt from taxation

(v) Payments made to reduce or buy down the purchase price of oil produced in later periods by allocating such payments over the production whose price that the payment reduces and including the allocated amounts as proceeds for the production as it occurs

(vi) Monies and all other consideration to which a seller is contractually or legally entitled but does not seek to collect through reasonable efforts

(2) *Gas, residue gas, and gas plant products.* Gross proceeds also include, but are not limited to, the following examples:

(i) Payments for services such as dehydration, marketing, measurement, or gathering that the lessee must perform at no cost to the Federal Government

(ii) Reimbursements for royalties, fees, and any other reimbursements

(iii) Tax reimbursements, even though the Federal royalty interest may be exempt from taxation

(iv) Monies and all other consideration to which a seller is contractually or legally entitled, but does not seek to collect through reasonable efforts

(3) *Coal.* Gross proceeds also include, but are not limited to, the following examples:

(i) Payments for services such as crushing, sizing, screening, storing, mixing, loading, treatment with substances including chemicals or oil, and other preparation of the coal that the lessee must perform at no cost to the Federal Government or Indian lessor

(ii) Reimbursements for royalties, fees, and any other reimbursements

(iii) Tax reimbursements even though the Federal or Indian royalty interest may be exempt from taxation

(iv) Monies and all other consideration to which a seller is contractually or legally entitled, but does not seek to collect through reasonable efforts

Index means:

(1) For gas, the calculated composite price ($/MMBtu) of spot market sales that a publication that meets ONRR-established criteria for acceptability at the index pricing point publishes

(2) For oil, the calculated composite price ($/barrel) of spot market sales that a publication that meets ONRR-established criteria for acceptability at the index pricing point publishes.

Index pricing point means any point on a pipeline for which there is an index, which ONRR-approved publications may refer to as a trading location.

Index zone means a field or an area with an active spot market and published indices applicable to that field or an area that is acceptable to ONRR under § 1206.141(d)(1).

Indian Tribe means any Indian Tribe, band, nation, pueblo, community, rancheria, colony, or other group of Indians for which any minerals or interest in minerals is held in trust by the United States or is subject to Federal restriction against alienation.

Individual Indian mineral owner means any Indian for whom minerals or an interest in minerals is held in trust by the United States or who holds title subject to Federal restriction against alienation.

Keepwhole contract means a processing agreement under which the processor delivers to the lessee a quantity of gas after processing equivalent to the quantity of gas that the processor received from the lessee prior to processing, normally based on heat content, less gas used as plant fuel and gas unaccounted for and/or lost. This includes, but is not limited to, agreements under which the processor retains all NGLs that it recovered from the lessee's gas.

Lease means any contract, profit-sharing arrangement, joint venture, or other agreement issued or approved by the United States under any mineral leasing law, including the Indian Mineral Development Act, 25 U.S.C. 2101–2108, that authorizes exploration for, extraction of, or removal of lease products. Depending on the context, lease may also refer to the land area that the authorization covers.

Lease products mean any leased minerals, attributable to, originating from, or allocated to a lease or produced in association with a lease.

Lessee means any person to whom the United States, an Indian Tribe, and/or Individual Indian mineral owner issues a lease, and any person who has been assigned all or a part of record title, operating rights, or an obligation to make royalty or other payments required by the lease. Lessee includes:

(1) Any person who has an interest in a lease.

(2) In the case of leases for Indian coal or Federal coal, an operator, payor, or other person with no lease interest who makes royalty payments on the lessee's behalf.

Like quality means similar chemical and physical characteristics.

Location differential means an amount paid or received (whether in money or in barrels of oil) under an exchange agreement that results from differences in location between oil delivered in exchange and oil received in the exchange. A location differential may represent all or part of the difference between the price received for oil delivered and the price paid for oil received under a buy/sell exchange agreement.

Market center means a major point that ONRR recognizes for oil sales, refining, or transshipment. Market centers generally are locations where ONRR-approved publications publish oil spot prices.

Marketable condition means lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area for Federal oil and gas, and region for Federal and Indian coal.

Mine means an underground or surface excavation or series of excavations and the surface or underground support facilities that contribute directly or indirectly to mining, production, preparation, and handling of lease products.

Net output means the quantity of:

(1) For gas, residue gas and each gas plant product that a processing plant produces.

(2) For coal, the quantity of washed coal that a coal wash plant produces.

Netting means reducing the reported sales value to account for an allowance instead of reporting the allowance as a separate entry on the Report of Sales and Royalty Remittance (Form ONRR–2014) or the Solid Minerals Production and Royalty Report (Form ONRR–4430).

NGLs means Natural Gas Liquids.

NYMEX price means the average of the New York Mercantile Exchange (NYMEX) settlement prices for light sweet crude oil delivered at Cushing, Oklahoma, calculated as follows:

(1) First, sum the prices published for each day during the calendar month of production (excluding weekends and holidays) for oil to be delivered in the prompt month corresponding to each such day.

(2) Second, divide the sum by the number of days on which those prices are published (excluding weekends and holidays).

Oil means a mixture of hydrocarbons that existed in the liquid phase in natural underground reservoirs, remains liquid at atmospheric pressure after passing through surface separating facilities, and is marketed or used as a liquid. Condensate recovered in lease separators or field facilities is oil.

ONRR means the Office of Natural Resources Revenue of the Department of the Interior.

ONRR-approved commercial price bulletin means a publication that ONRR approves for determining NGLs prices.

ONRR-approved publication means:

(1) For oil, a publication that ONRR approves for determining ANS spot prices or WTI differentials.

(2) For gas, a publication that ONRR approves for determining index pricing points.

Outer Continental Shelf (OCS) means all submerged lands lying seaward and outside of the area of lands beneath navigable waters, as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301), and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Payor means any person who reports and pays royalties under a lease, regardless of whether that person also is a lessee.

Person means any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity).

Processing means any process designed to remove elements or compounds (hydrocarbon and non-hydrocarbon) from gas, including absorption, adsorption, or refrigeration. Field processes which normally take place on or near the lease, such as natural pressure reduction, mechanical separation, heating, cooling, dehydration, and compression, are not considered processing. The changing of pressures and/or temperatures in a reservoir is not considered processing. The use of a Joule-Thomson (JT) unit to remove NGLs from gas is considered processing regardless of where the JT unit is located, provided that you market the NGLs as NGLs.

Processing allowance means a deduction in determining royalty value for the reasonable, actual costs the lessee incurs for processing gas.

Prompt month means the nearest month of delivery for which NYMEX futures prices are published during the trading month.

Quality differential means an amount paid or received under an exchange agreement (whether in money or in barrels of oil) that results from differences in API gravity, sulfur content, viscosity, metals content, and other quality factors between oil delivered and oil received in the exchange. A quality differential may represent all or part of the difference between the price received for oil delivered and the price paid for oil received under a buy/sell agreement.

Region for coal means the eight Federal coal production regions, which the Bureau of Land Management designates as follows: Denver-Raton Mesa Region, Fort Union Region, Green River-Hams Fork Region, Powder River Region, San Juan River Region, Southern Appalachian Region, Uinta-Southwestern Utah Region, and Western Interior Region. See 44 FR 65197 (1979).

Residue gas means that hydrocarbon gas consisting principally of methane resulting from processing gas.

Rocky Mountain Region means the States of Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming, except for those portions of the San Juan Basin and other oil-producing fields in the ''Four Corners'' area that lie within Colorado and Utah.

Roll means an adjustment to the NYMEX price that is calculated as follows:

$$\text{Roll} = .6667 \times (P_0 - P_1) + .3333 \times (P_0 - P_2),$$

where: P_0 = the average of the daily NYMEX settlement prices for deliveries during the prompt month that is the same as the month of production, as published for each day during the trading month for which the month of production is the prompt month; P_1 = the average of the daily NYMEX settlement prices for deliveries during the month following the month of production, published for each day during the trading month for which the month of production is the prompt month; and P_2 = the average of the daily NYMEX settlement prices for deliveries during the second month following the month of production, as published for each day during the trading month for which the month of production is the prompt month. Calculate the average of the daily NYMEX settlement prices using only the days on which such prices are published (excluding weekends and holidays).

(1) *Example 1. Prices in Out Months are Lower Going Forward:* The month of production for which you must determine royalty value is December. December was the prompt month (for year 2011) from October 21 through November 18. January was the first month following the month of production, and February was the second month following the month of production. P_0 therefore, is the average of the daily NYMEX settlement prices for deliveries during December published for each business day between October 21 and November 18. P_1 is the average of the daily NYMEX settlement prices for deliveries during January published for each business day between October 21 and November 18. P_2 is the average of the daily NYMEX settlement prices for deliveries during February published for each business day between October 21 and November 18. In this example, assume that P_0 = \$95.08 per bbl, P_1 = \$95.03 per bbl, and P_2 = \$94.93 per bbl. In this example (a declining market), Roll = .6667 × (\$95.08 − \$95.03) + .3333 × (\$95.08 − \$94.93) = \$0.03 + \$0.05 = \$0.08. You add this number to the NYMEX price.

(2) *Example 2. Prices in Out Months are Higher Going Forward:* The month of production for which you must determine royalty value is November. November was the prompt month (for year 2012) from September 21 through October 22. December was the first month following the month of production, and January was the second month following the month of production. P_0 therefore, is the average of the daily NYMEX settlement prices for deliveries during November published for each business day between September 21 and October 22. P_1 is the average of the daily NYMEX settlement prices for deliveries during December published for each business day between September 21 and October 22. P_2 is the average of the daily NYMEX settlement prices for deliveries during January published for each business day between September 21 and October 22. In this example, assume that P_0 = \$91.28 per bbl, P_1 = \$91.65 per bbl, and P_2 = \$92.10 per bbl. In this example (a rising market), Roll = .6667 × (\$91.28 − \$91.65) + .3333 × (\$91.28 − \$92.10) = (−\$0.25) + (−\$0.27) = (−\$0.52). You add this negative number to the NYMEX price (effectively, a subtraction from the NYMEX price).

Sale means a contract between two persons where:

(1) The seller unconditionally transfers title to the oil, gas, gas plant product, or coal to the buyer and does not retain any related rights, such as the right to buy back similar quantities of oil, gas, gas plant product, or coal from the buyer elsewhere;

(2) The buyer pays money or other consideration for the oil, gas, gas plant product, or coal; and

(3) The parties' intent is for a sale of the oil, gas, gas plant product, or coal to occur.

Section 6 lease means an OCS lease subject to section 6 of the Outer Continental Shelf Lands Act, as amended, 43 U.S.C. 1335.

Short ton means 2,000 pounds.

Spot price means the price under a spot sales contract where:

(1) A seller agrees to sell to a buyer a specified amount of oil at a specified price over a specified period of short duration.

(2) No cancellation notice is required to terminate the sales agreement.

(3) There is no obligation or implied intent to continue to sell in subsequent periods.

Tonnage means tons of coal measured in short tons.

Trading month means the period extending from the second business day before the 25th day of the second calendar month preceding the delivery month (or, if the 25th day of that month is a non-business day, the second business day before the last business day preceding the 25th day of that month) through the third business day before the 25th day of the calendar month preceding the delivery month (or, if the 25th day of that month is a non-business day, the third business day before the last business day preceding the 25th day of that month), unless the NYMEX publishes a different definition or different dates on its official website, *www.cmegroup.com,* in which case, the NYMEX definition will apply.

Transportation allowance means a deduction in determining royalty value for the reasonable, actual costs that the lessee incurs for moving:

(1) Oil to a point of sale or delivery off of the lease, unit area, or communitized area. The transportation allowance does not include gathering costs.

(2) Unprocessed gas, residue gas, or gas plant products to a point of sale or delivery off of the lease, unit area, or communitized area, or away from a processing plant. The transportation allowance does not include gathering costs.

(3) Coal to a point of sale remote from both the lease and mine or wash plant.

Washing allowance means a deduction in determining royalty value for the reasonable, actual costs the lessee incurs for coal washing.

WTI differential means the average of the daily mean differentials for location and quality between a grade of crude oil at a market center and West Texas Intermediate (WTI) crude oil at Cushing published for each day for which price publications perform surveys for deliveries during the production month, calculated over the number of days on which those differentials are published (excluding weekends and holidays). Calculate the daily mean differentials by averaging the daily high and low differentials for the month in the selected publication. Use only the days and corresponding differentials for which such differentials are published.

Subpart C—Federal Oil

■ 3. Revise § 1206.101 to read as follows:

§ 1206.101 How do I calculate royalty value for oil I or my affiliate sell(s) under an arm's-length contract?

(a) The value of oil under this section for royalty purposes is the gross proceeds accruing to you or your affiliate under the arm's-length contract less applicable allowances determined under § 1206.111 or 1206.112. This value does not apply if you exercise an option to use a different value provided in paragraph (c)(1) or (c)(2)(i) of this section, or if one of the exceptions in paragraph (d) of this section applies. You must use this paragraph (a) to value oil when:

(1) You sell under an arm's-length sales contract; or

(2) You sell or transfer to your affiliate or another person under a non-arm's-length contract and that affiliate or person, or another affiliate of either of them, then sells the oil under an arm's-length contract, unless you exercise the

option provided in paragraph (c)(2)(i) of this section.

(b) If you have multiple arm's-length contracts to sell oil produced from a lease that is valued under paragraph (a) of this section, the value of the oil is the volume-weighted average of the values established under this section for each contract for the sale of oil produced from that lease.

(c)(1) If you enter into an arm's-length exchange agreement, or multiple sequential arm's-length exchange agreements, and following the exchange(s) that you or your affiliate sell(s) the oil received in the exchange(s) under an arm's-length contract, then you may use either paragraph (a) of this section or § 1206.102 to value your production for royalty purposes. If you fail to make the election required under this paragraph, you may not make a retroactive election.

(i) If you use paragraph (a) of this section, your gross proceeds are the gross proceeds under your or your affiliate's arm's-length sales contract after the exchange(s) occur(s). You must adjust your gross proceeds for any location or quality differential, or other adjustments, that you received or paid under the arm's-length exchange agreement(s). If ONRR determines that any arm's-length exchange agreement does not reflect reasonable location or quality differentials, ONRR may require you to value the oil under § 1206.102. You may not otherwise use the price or differential specified in an arm's-length exchange agreement to value your production.

(ii) When you elect under § 1206.101(c)(1) to use paragraph (a) of this section or § 1206.102, you must make the same election for all of your production from the same unit, communitization agreement, or lease (if the lease is not part of a unit or communitization agreement) sold under arm's-length contracts following arm's-length exchange agreements. You may not change your election more often than once every two years.

(2)(i) If you sell or transfer your oil production to your affiliate, and that affiliate or another affiliate then sells the oil under an arm's-length contract, you may use either paragraph (a) of this section or § 1206.102 to value your production for royalty purposes.

(ii) When you elect under paragraph (c)(2)(i) of this section to use paragraph (a) of this section or § 1206.102, you must make the same election for all of your production from the same unit, communitization agreement, or lease (if the lease is not part of a unit or communitization agreement) that your affiliates resell at arm's-length. You may not change your election more often than once every two years.

(d) This paragraph contains exceptions to the valuation rule in paragraph (a) of this section. Apply these exceptions on an individual contract basis.

(1) In conducting reviews and audits, if ONRR determines that any arm's-length sales contract does not reflect the total consideration actually transferred either directly or indirectly from the buyer to the seller, ONRR may require that you value the oil sold under that contract either under § 1206.102 or at the total consideration received.

(2) You must value the oil under § 1206.102 if ONRR determines that the value under paragraph (a) of this section does not reflect the reasonable value of the production due to either:

(i) Misconduct by or between the parties to the arm's-length contract; or

(ii) Breach of your duty to market the oil for the mutual benefit of yourself and the lessor.

■ 4. Revise § 1206.102 to read as follows:

§ 1206.102 How do I value oil not sold under an arm's-length contract?

This section explains how to value oil that you may not value under § 1206.101 or that you elect under § 1206.101(c)(1) to value under this section. First, determine if paragraph (a), (b), or (c) of this section applies to production from your lease, or if you may apply paragraph (d) or (e) with ONRR's approval.

(a) *Production from leases in California or Alaska.* Value is the average of the daily mean ANS spot prices published in any ONRR-approved publication during the trading month most concurrent with the production month. For example, if the production month is June, calculate the average of the daily mean prices using the daily ANS spot prices published in the ONRR-approved publication for all of the business days in June.

(1) To calculate the daily mean spot price, you must average the daily high and low prices for the month in the selected publication.

(2) You must use only the days and corresponding spot prices for which such prices are published.

(3) You must adjust the value for applicable location and quality differentials, and you may adjust it for transportation costs, under § 1206.111.

(4) After you select an ONRR-approved publication, you may not select a different publication more often than once every two years, unless the publication you use is no longer published or ONRR revokes its approval of the publication. If you must change publications, you must begin a new two-year period.

(b) *Production from leases in the Rocky Mountain Region.* This paragraph provides methods and options for valuing your production under different factual situations. You must consistently apply paragraph (b)(2) or (3) of this section to value all of your production from the same unit, communitization agreement, or lease (if the lease or a portion of the lease is not part of a unit or communitization agreement) that you cannot value under § 1206.101 or that you elect under § 1206.101(c)(1) to value under this section.

(1) You may elect to value your oil under either paragraph (b)(2) or (3) of this section. After you select either paragraph (b)(2) or (3) of this section, you may not change to the other method more often than once every two years, unless the method you have been using is no longer applicable and you must apply the other paragraph. If you change methods, you must begin a new two-year period.

(2) Value is the volume-weighted average of the gross proceeds accruing to the seller under your or your affiliate's arm's-length contracts for the purchase or sale of production from the field or area during the production month.

(i) The total volume purchased or sold under those contracts must exceed 50 percent of your and your affiliate's production from both Federal and non-Federal leases in the same field or area during that month.

(ii) Before calculating the volume-weighted average, you must normalize the quality of the oil in your or your affiliate's arm's-length purchases or sales to the same gravity as that of the oil produced from the lease.

(3) Value is the NYMEX price (without the roll), adjusted for applicable location and quality differentials and transportation costs under § 1206.113.

(4) If you demonstrate to ONRR's satisfaction that paragraphs (b)(2) through (3) of this section result in an unreasonable value for your production as a result of circumstances regarding that production, ONRR's Director may establish an alternative valuation method.

(c) *Production from leases not located in California, Alaska, or the Rocky Mountain Region.* (1) Value is the NYMEX price, plus the roll, adjusted for applicable location and quality differentials and transportation costs under § 1206.113.

(2) If ONRR's Director determines that the use of the roll no longer reflects prevailing industry practice in crude oil sales contracts or that the most common formula that industry uses to calculate the roll changes, ONRR may terminate or modify the use of the roll under paragraph (c)(1) of this section at the end of each two-year period as of January 1, 2017, through a notice published in the **Federal Register** not later than 60 days before the end of the two-year period. ONRR will explain the rationale for terminating or modifying the use of the roll in this notice.

(d) *Unreasonable value.* If ONRR determines that the NYMEX price or ANS spot price does not represent a reasonable royalty value in any particular case, ONRR may establish a reasonable royalty value based on other relevant matters.

(e) *Production delivered to your refinery and the NYMEX price or ANS spot price is an unreasonable value.* (1) Instead of valuing your production under paragraph (a), (b), or (c) of this section, you may apply to ONRR to establish a value representing the market at the refinery if:

(i) You transport your oil directly to your or your affiliate's refinery, or exchange your oil for oil delivered to your or your affiliate's refinery; and

(ii) You must value your oil under this section at the NYMEX price or ANS spot price; and

(iii) You believe that use of the NYMEX price or ANS spot price results in an unreasonable royalty value.

(2) You must provide adequate documentation and evidence demonstrating the market value at the refinery. That evidence may include, but is not limited to:

(i) Costs of acquiring other crude oil at or for the refinery;

(ii) How adjustments for quality, location, and transportation were factored into the price paid for other oil;

(iii) Volumes acquired for and refined at the refinery; and

(iv) Any other appropriate evidence or documentation that ONRR requires.

(3) If ONRR establishes a value representing market value at the refinery, you may not take an allowance against that value under § 1206.113(b) unless it is included in ONRR's approval.

■ 5. Revise § 1206.104 to read as follows:

§ 1206.104 How will ONRR determine if my royalty payments are correct?

(a)(1) ONRR may monitor, review, and audit the royalties that you report, and, if ONRR determines that your reported value is inconsistent with the requirements of this subpart, ONRR may establish a reasonable royalty value based on other relevant matters.

(2) If ONRR directs you to use a different royalty value, you must either pay any additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter, or report a credit for—or request a refund of—any overpaid royalties.

(b) ONRR may examine whether your or your affiliate's contract reflects the total consideration transferred for Federal oil, either directly or indirectly, from the buyer to you or your affiliate. If ONRR determines that additional consideration beyond that reflected in the contract was transferred, or that any portion of the consideration was not included in gross proceeds reported, ONRR may establish a reasonable royalty value based on other relevant matters.

(c) ONRR may establish a reasonable royalty value based on other relevant matters if ONRR determines that the gross proceeds accruing to you or your affiliate under a contract do not reflect reasonable consideration because:

(1) There is misconduct by or between the contracting parties;

(2) You have breached your duty to market the oil for the mutual benefit of yourself and the lessor; or

(3) ONRR cannot determine if you properly valued your oil under § 1206.101 or § 1206.102 for any reason including—but not limited to—your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart B.

(d) You have the burden of demonstrating that your or your affiliate's contract is arm's-length.

(e) ONRR may require you to certify that the provisions in your or your affiliate's contract include all of the consideration that the buyer paid to you or your affiliate, either directly or indirectly, for the oil.

(f)(1) Absent contract revision or amendment, if you or your affiliate fail(s) to take proper or timely action to receive prices or benefits to which you or your affiliate are entitled, you must pay royalty based upon that obtainable price or benefit.

(2) If you or your affiliate apply in a timely manner for a price increase or benefit allowed under your or your affiliate's contract, but the purchaser refuses and you or your affiliate take reasonable documented measures to force purchaser compliance, you will not owe additional royalties unless or until you or your affiliate receive additional monies or consideration resulting from the price increase. You may not construe this paragraph to permit you to avoid your royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or in a timely manner, for a quantity of oil.

(g)(1) You or your affiliate must put all contracts, contract revisions, or amendments in writing.

(2) If you or your affiliate fail(s) to comply with paragraph (g)(1) of this section, ONRR may establish a reasonable royalty value based on other relevant matters.

(3) This provision applies notwithstanding any other provisions in this title 30 to the contrary.

■ 6. Remove and reserve § 1206.105.

§ 1206.105 [Reserved]

■ 7. Revise § 1206.108 to read as follows:

§ 1206.108 How do I request a valuation determination?

(a) You may request a valuation determination from ONRR regarding any oil produced. Your request must comply with all of the following:

(1) Be in writing.

(2) Identify, specifically, all leases involved, all interest owners of those leases, the designee(s), and the operator(s) for those leases.

(3) Completely explain all relevant facts; you must inform ONRR of any changes to relevant facts that occur before we respond to your request.

(4) Include copies of all relevant documents.

(5) Provide your analysis of the issue(s).

(6) Suggest your proposed valuation method.

(b) In response to your request, ONRR may:

(1) Request that the Assistant Secretary for Policy, Management and Budget issue a valuation determination;

(2) Decide that ONRR will issue guidance; or

(3) Inform you in writing that ONRR will not provide a determination or guidance. Situations in which ONRR typically will not provide any determination or guidance include, but are not limited to, the following:

(i) Requests for guidance on hypothetical situations.

(ii) Matters that are the subject of pending litigation or administrative appeals.

(c)(1) A valuation determination that the Assistant Secretary for Policy, Management and Budget signs is binding on both you and ONRR until the Assistant Secretary modifies or rescinds it.

(2) After the Assistant Secretary for Policy, Management and Budget issues

a valuation determination, you must make any adjustments to royalty payments that follow from the determination and, if you owe additional royalties, you must pay the additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter.

(3) A valuation determination that the Assistant Secretary for Policy, Management and Budget signs is the final action of the Department and is subject to judicial review under 5 U.S.C. 701–706.

(d) Guidance that ONRR issues is not binding on ONRR, delegated States, or you with respect to the specific situation addressed in the guidance.

(1) Guidance and ONRR's decision whether or not to issue guidance or request an Assistant Secretary for Policy, Management and Budget determination, or neither, under paragraph (b) of this section, are not appealable decisions or orders under 30 CFR part 1290.

(2) If you receive an order requiring you to pay royalty on the same basis as the guidance, you may appeal that order under 30 CFR part 1290.

(e) ONRR or the Assistant Secretary for Policy, Management and Budget may use any of the applicable valuation criteria in this subpart to provide guidance or to make a determination.

(f) A change in an applicable statute or regulation on which ONRR or the Assistant Secretary for Policy, Management and Budget based any determination or guidance takes precedence over the determination or guidance, regardless of whether ONRR or the Assistant Secretary modifies or rescinds the determination or guidance.

(g) ONRR or the Assistant Secretary for Policy, Management and Budget generally will not retroactively modify or rescind a valuation determination issued under paragraph (d) of this section, unless:

(1) There was a misstatement or omission of material facts; or

(2) The facts subsequently developed are materially different from the facts on which the guidance was based.

(h) ONRR may make requests and replies under this section available to the public, subject to the confidentiality requirements under § 1206.109.

■ 8. Revise § 1206.110 to read as follows:

§ 1206.110 What general transportation allowance requirements apply to me?

(a) ONRR will allow a deduction for the reasonable, actual costs to transport oil from the lease to the point off of the lease under § 1206.110, 1206.111, or 1206.112, as applicable. You may not deduct transportation costs that you incur to move a particular volume of production to reduce royalties that you owe on production for which you did not incur those costs. This paragraph applies when:

(1)(i) The movement to the sales point is not gathering except

(ii) For oil produced on the OCS in waters deeper than 200 meters, the movement of oil from the wellhead to the first platform is transportation for which a transportation allowance may be claimed; and

(iii) On a case-by-case basis, you may apply to ONRR to have your actual, reasonable and necessary costs of the movement of oil produced on the OCS in waters shallower than 200 meters from the wellhead to the first platform to be treated as transportation for which a transportation allowance may be claimed.

(2) You value oil under § 1206.101 based on a sale at a point off of the lease, unit, or communitized area where the oil is produced; or

(3) You do not value your oil under § 1206.102(a)(3) or (b)(3).

(b) You must calculate the deduction for transportation costs based on your or your affiliate's cost of transporting each product through each individual transportation system. If your or your affiliate's transportation contract includes more than one liquid product, you must allocate costs consistently and equitably to each of the liquid products that are transported. Your allocation must use the same proportion as the ratio of the volume of each liquid product (excluding waste products with no value) to the volume of all liquid products (excluding waste products with no value).

(1) You may not take an allowance for transporting lease production that is not royalty-bearing.

(2) You may propose to ONRR a prospective cost allocation method based on the values of the liquid products transported. ONRR will approve the method if it is consistent with the purposes of the regulations in this subpart.

(3) You may use your proposed procedure to calculate a transportation allowance beginning with the production month following the month when ONRR received your proposed procedure until ONRR accepts or rejects your cost allocation. If ONRR rejects your cost allocation, you must amend your Form ONRR–2014 for the months that you used the rejected method and pay any additional royalty due, plus late payment interest.

(c)(1) Where you or your affiliate transport(s) both gaseous and liquid products through the same transportation system, you must propose a cost allocation procedure to ONRR.

(2) You may use your proposed procedure to calculate a transportation allowance until ONRR accepts or rejects your cost allocation. If ONRR rejects your cost allocation, you must amend your Form ONRR–2014 for the months when you used the rejected method and pay any additional royalty and interest due.

(3) You must submit your initial proposal, including all available data, within three months after you first claim the allocated deductions on Form ONRR–2014.

(d)(1) Your transportation allowance may not exceed 50 percent of the value of the oil, as determined under § 1206.101, except as provided in paragraph (d)(2) of this section.

(2) You may ask ONRR to approve a transportation allowance in excess of the limitation in paragraph (d)(1) of this section. You must demonstrate that the transportation costs incurred were reasonable, actual, and necessary. Your application for exception (using Form ONRR–4393, Request to Exceed Regulatory Allowance Limitation) must contain all relevant and supporting documentation necessary for ONRR to make a determination. You may never reduce the royalty value of any production to zero.

(e) You must express transportation allowances for oil as a dollar-value equivalent. If your or your affiliate's payments for transportation under a contract are not on a dollar-per-unit basis, you must convert whatever consideration you or your affiliate are paid to a dollar-value equivalent.

(f) ONRR may direct you to modify your transportation allowance if:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration that you or your affiliate paid under an arm's-length transportation contract does not reflect the reasonable cost of the transportation because you breached your duty to market the oil for the mutual benefit of yourself and the lessor by transporting your oil at a cost that is unreasonably high; or

(3) ONRR cannot determine if you properly calculated a transportation allowance under § 1206.111 or 1206.112 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart B.

(g) You do not need ONRR's approval before reporting a transportation allowance.

■ 9. Revise § 1206.111 to read as follows:

§ 1206.111 How do I determine a transportation allowance if I have an arm's-length transportation contract?

(a)(1) If you or your affiliate incur transportation costs under an arm's-length transportation contract, you may claim a transportation allowance for the reasonable, actual costs incurred, as stated in paragraph (b) of this section, except as provided in § 1206.110(f) and subject to the limitation in § 1206.110(d).

(2) You must be able to demonstrate that your or your affiliate's contract is at arm's length.

(3) You do not need ONRR's approval before reporting a transportation allowance for costs incurred under an arm's-length transportation contract.

(b) Subject to the requirements of paragraph (c) of this section, you may include, but are not limited to, the following costs to determine your transportation allowance under paragraph (a) of this section; you may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section including, but not limited to:

(1) The amount that you pay under your arm's-length transportation contract or tariff.

(2) Fees paid (either in volume or in value) for actual or theoretical line losses.

(3) Fees paid for administration of a quality bank.

(4) Fees paid to a terminal operator for loading and unloading of crude oil into or from a vessel, vehicle, pipeline, or other conveyance.

(5) Fees paid for short-term storage (30 days or less) incidental to transportation as a transporter requires.

(6) Fees paid to pump oil to another carrier's system or vehicles as required under a tariff.

(7) Transfer fees paid to a hub operator associated with physical movement of crude oil through the hub when you do not sell the oil at the hub. These fees do not include title transfer fees.

(8) Payments for a volumetric deduction to cover shrinkage when high-gravity petroleum (generally in excess of 51 degrees API) is mixed with lower gravity crude oil for transportation.

(9) Costs of securing a letter of credit, or other surety, that the pipeline requires you, as a shipper, to maintain.

(10) Hurricane surcharges that you or your affiliate actually pay(s).

(11) The cost of carrying on your books as inventory a volume of oil that the pipeline operator requires you, as a shipper, to maintain and that you do maintain in the line as line fill. You must calculate this cost as follows:

(i) First, multiply the volume that the pipeline requires you to maintain—and that you do maintain—in the pipeline by the value of that volume for the current month calculated under § 1206.101 or 1206.102, as applicable.

(ii) Second, multiply the value calculated under paragraph (b)(11)(i) of this section by the monthly rate of return, calculated by dividing the rate of return specified in § 1206.112(i)(3) by 12.

(c) You may not include any of the following costs to determine your transportation allowance under paragraph (a) of this section:

(1) Fees paid for long-term storage (more than 30 days).

(2) Administrative, handling, and accounting fees associated with terminalling.

(3) Title and terminal transfer fees.

(4) Fees paid to track and match receipts and deliveries at a market center or to avoid paying title transfer fees.

(5) Fees paid to brokers.

(6) Fees paid to a scheduling service provider.

(7) Internal costs, including salaries and related costs, rent/space costs, office equipment costs, legal fees, and other costs to schedule, nominate, and account for sale or movement of production.

(8) Gauging fees.

(d) (1) If you have no written contract for the arm's-length transportation of oil, you must propose to ONRR a method to determine the allowance using the procedures in § 1206.108(a).

(2) You may use that method to determine your allowance until ONRR issues its determination.

■ 10. Revise § 1206.117 to read as follows:

§ 1206.117 What interest and penalties apply if I improperly report a transportation allowance?

(a) If you deduct a transportation allowance on Form ONRR–2014 that exceeds 50 percent of the value of the oil transported without obtaining ONRR's prior approval under § 1206.110(d)(2), you must pay additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter, on the excess allowance amount taken from the date when that amount is taken to the date when you file an exception request that ONRR approves. If you do not file an exception request, or if ONRR does not approve your request, you must pay late payment interest on the excess allowance amount taken from the date that amount is taken until the date you pay the additional royalties owed.

(b) If you improperly net a transportation allowance against the oil instead of reporting the allowance as a separate entry on Form ONRR–2014, ONRR may assess a civil penalty under 30 CFR part 1241.

Subpart D—Federal Gas

■ 11. Revise § 1206.141 to read as follows:

§ 1206.141 How do I calculate royalty value for unprocessed gas that I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?

(a) This section applies to unprocessed gas. Unprocessed gas is:

(1) Gas that is not processed;

(2) Any gas that you are not required to value under § 1206.142; or

(3) Any gas that you sell prior to processing based on a price per MMBtu or Mcf when the price is not based on the residue gas and gas plant products.

(b) The value of gas under this section for royalty purposes is the gross proceeds accruing to you or your affiliate under the first arm's-length contract less a transportation allowance determined under § 1206.152. This value does not apply if you exercise the option in paragraph (c) of this section. Unless you elect to value your gas under paragraph (c) of this section, you must use this paragraph (b) to value gas when:

(1) You sell under an arm's-length contract;

(2) You sell or transfer unprocessed gas to your affiliate or another person under a non-arm's-length contract and that affiliate or person, or an affiliate of either of them, then sells the gas under an arm's-length contract;

(3) You, your affiliate, or another person sell(s) unprocessed gas produced from a lease under multiple arm's-length contracts, and that gas is valued under this paragraph. The value of the gas is the volume-weighted average of the values, established under this paragraph, for each contract for the sale of gas produced from that lease; or

(4) You or your affiliate sell(s) under a pipeline cash-out program. In that case, for over-delivered volumes within the tolerance under a pipeline cash-out program, the value is the price that the pipeline must pay you or your affiliate under the transportation contract. You must use the same value for volumes that exceed the over-delivery tolerances, even if those volumes are subject to a

lower price under the transportation contract.

(c) Alternatively, you may elect to value your unprocessed gas under this paragraph (c), which allows you to use an index-based valuation method to calculate royalty value. You may not change your election more often than once every two years.

(1)(i) If you can only transport gas to one index pricing point published in an ONRR-approved publication, available at *www.onrr.gov,* your value, for royalty purposes, is the published average bidweek price to which your gas may flow for that respective production month.

(ii) If you can transport gas to more than one index pricing point published in an ONRR-approved publication available at *www.onrr.gov,* your value, for royalty purposes, is the highest of the published average bidweek prices to which your gas may flow for that respective production month, whether or not there are constraints for that production month.

(iii) If there are sequential index pricing points on a pipeline, you must use the first index pricing point at or after your gas enters the pipeline.

(iv) You may adjust the number calculated under paragraphs (c)(1)(i) and (ii) of this section by reducing the value by 10 percent, but not less than 10 cents per MMBtu nor more than 40 cents per MMBtu for sales from the OCS Gulf of Mexico and by 15 percent, but not less than 10 cents per MMBtu nor more than 50 cents per MMBtu, for sales from all other areas.

(v) After you select an ONRR-approved publication available at *www.onrr.gov,* you may not select a different publication more often than once every two years.

(vi) ONRR may exclude an individual index pricing point found in an ONRR-approved publication if ONRR determines that the index pricing point does not accurately reflect the values of production. ONRR will publish criteria for index pricing points available at *www.onrr.gov.*

(2) You may not take any other deductions from the value calculated under this paragraph (c).

(d) If some of your gas is used, lost, unaccounted for, or retained as a fee under the terms of a sales or service agreement, that gas will be valued for royalty purposes using the same royalty valuation method for valuing the rest of the gas that you do sell.

(e) If you have no written contract for the sale of gas or no sale of gas subject to this section and:

(1) There is an index pricing point for the gas, then you must value your gas under paragraph (c) of this section; or

(2) There is not an index pricing point for the gas, then:

(i) You must propose to ONRR a method to determine the value using the procedures in § 1206.148(a).

(ii) You may use that method to determine value, for royalty purposes, until ONRR issues its decision.

(iii) After ONRR issues its determination, you must make the adjustments under § 1206.143(a)(2).

(f) Under no circumstances may your gas be valued for royalty purposes at or less than zero.

(g) If you elect to value your gas under paragraph (c) of this section, ONRR reserves the right to collect actual transaction data in the future to assess the validity of the index-based valuation option.

■ 12. Revise § 1206.142 to read as follows:

§ 1206.142 How do I calculate royalty value for processed gas that I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?

(a) This section applies to the valuation of processed gas, including but not limited to:

(1) Gas that you or your affiliate do not sell, or otherwise dispose of, under an arm's-length contract prior to processing.

(2) Gas where your or your affiliate's arm's-length contract for the sale of gas prior to processing provides for payment to be determined on the basis of the value of any products resulting from processing, including residue gas or natural gas liquids.

(3) Gas that you or your affiliate process under an arm's-length keepwhole contract.

(4) Gas where your or your affiliate's arm's-length contract includes a reservation of the right to process the gas, and you or your affiliate exercise(s) that right.

(b) The value of gas subject to this section, for royalty purposes, is the combined value of the residue gas and all gas plant products that you determine under this section plus the value of any condensate recovered downstream of the point of royalty settlement without resorting to processing that you determine under subpart C of this part less applicable transportation and processing allowances that you determine under this subpart, unless you exercise the option provided in paragraph (d) of this section.

(c) The value of residue gas or any gas plant product under this section for royalty purposes is the gross proceeds accruing to you or your affiliate under the first arm's-length contract. This value does not apply if you exercise the option provided in paragraph (d) of this section. Unless you exercise the option provided in paragraph (d) of this section, you must use this paragraph (c) to value residue gas or any gas plant product when:

(1) You sell under an arm's-length contract;

(2) You sell or transfer to your affiliate or another person under a non-arm's-length contract, and that affiliate or person, or another affiliate of either of them, then sells the residue gas or any gas plant product under an arm's-length contract;

(3) You, your affiliate, or another person sell(s), under multiple arm's-length contracts, residue gas or any gas plant products recovered from gas produced from a lease that you value under this paragraph. In that case, because you sold non-arm's-length to your affiliate or another person, the value of the residue gas or any gas plant product is the volume-weighted average of the gross proceeds established under this paragraph for each arm's-length contract for the sale of residue gas or any gas plant products recovered from gas produced from that lease; or

(4) You or your affiliate sell(s) under a pipeline cash-out program. In that case, for over-delivered volumes within the tolerance under a pipeline cash-out program, the value is the price that the pipeline must pay to you or your affiliate under the transportation contract. You must use the same value for volumes that exceed the over-delivery tolerances, even if those volumes are subject to a lower price under the transportation contract.

(d) Alternatively, you may elect to value your residue gas and NGLs under this paragraph (d). You may not change your election more often than once every two years.

(1)(i) If you can only transport residue gas to one index pricing point published in an ONRR-approved publication available at *www.onrr.gov,* your value, for royalty purposes, is the published average bidweek price to which your gas may flow for that respective production month.

(ii) If you can transport residue gas to more than one index pricing point published in an ONRR-approved publication available at *www.onrr.gov,* your value, for royalty purposes, is the highest of the published average bidweek prices to which your gas may flow for that respective production month, whether or not there are constraints for that production month.

(iii) If there are sequential index pricing points on a pipeline, you must use the first index pricing point at or after your residue gas enters the pipeline.

(iv) You may adjust the number calculated under paragraphs (d)(1)(i) and (ii) of this section by reducing the value by 10 percent, but not less than 10 cents per MMBtu nor more than 40 cents per MMBtu for sales from the OCS Gulf of Mexico and by 15 percent, but not less than 10 cents per MMBtu nor more than 50 cents per MMBtu for sales from all other areas.

(v) After you select an ONRR-approved publication available at *www.onrr.gov,* you may not select a different publication more often than once every two years.

(vi) ONRR may exclude an individual index pricing point found in an ONRR-approved publication if ONRR determines that the index pricing point does not accurately reflect the values of production. ONRR will publish criteria for index pricing points on *www.onrr.gov*.

(2)(i) If you sell NGLs in an area with one or more ONRR-approved commercial price bulletins available at *www.onrr.gov,* you must choose one bulletin, and your value, for royalty purposes, is the monthly average price for that bulletin for the production month.

(ii) You must reduce the number calculated under paragraph (d)(2)(i) of this section by the amounts that ONRR posts at *www.onrr.gov* for the geographic location of your lease. The method that ONRR will use to calculate the amounts is set forth in the preamble to this regulation. This method is binding on you and ONRR. ONRR will update the amounts periodically using this method.

(iii) After you select an ONRR-approved commercial price bulletin available at *www.onrr.gov,* you must not select a different commercial price bulletin more often than once every two years.

(3) You may not take any other deductions from the value calculated under this paragraph (d).

(4) ONRR will post changes to any of the rates in this paragraph (d) on its website.

(e) If some of your gas or gas plant products are used, lost, unaccounted for, or retained as a fee under the terms of a sales or service agreement, that gas will be valued for royalty purposes using the same royalty valuation method for valuing the rest of the gas or gas plant products that you do sell.

(f) If you have no written contract for the sale of gas or no sale of gas subject to this section and:

(1) There is an index pricing point or commercial price bulletin for the gas, then you must value your gas under paragraph (d) of this section.

(2) There is not an index pricing point or commercial price bulletin for the gas, then:

(i) You must propose to ONRR a method to determine the value using the procedures in § 1206.148(a).

(ii) You may use that method to determine value, for royalty purposes, until ONRR issues our decision.

(iii) After ONRR issues our determination, you must make the adjustments under § 1206.143(a)(2).

(g) Under no circumstances may your gas be valued for royalty purposes at or less than zero.

(h) If you elect to value your gas under paragraph (d) of this section, ONRR reserves the right to collect actual transaction data in the future to assess the validity of the index-based valuation option.

■ 13. Revise § 1206.143 to read as follows:

§ 1206.143 How will ONRR determine if my royalty payments are correct?

(a)(1) ONRR may monitor, review, and audit the royalties that you report. If ONRR determines that your reported value is inconsistent with the requirements of this subpart, ONRR will direct you to use a different measure of royalty value.

(2) If ONRR directs you to use a different royalty value, you must either pay any additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter, or report a credit for, or request a refund of, any overpaid royalties.

(b) ONRR may examine whether your or your affiliate's contract reflects the total consideration transferred for Federal gas, either directly or indirectly, from the buyer to you or your affiliate. If ONRR determines that additional consideration beyond that reflected in the contract was transferred, or that any portion of the consideration was not included in gross proceeds reported, ONRR may establish a reasonable royalty value based on other relevant matters.

(c) ONRR may direct you to use a different measure of royalty value if ONRR determines that the gross proceeds accruing to you or your affiliate under a contract do not reflect reasonable consideration because:

(1) There is misconduct by or between the contracting parties;

(2) You have breached your duty to market the gas, residue gas, or gas plant products for the mutual benefit of yourself and the lessor; or

(3) ONRR cannot determine if you properly valued your gas, residue gas, or gas plant products under § 1206.141 or § 1206.142 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart B.

(d) You have the burden of demonstrating that your or your affiliate's contract is arm's-length.

(e) ONRR may require you to certify that the provisions in your or your affiliate's contract include(s) all of the consideration that the buyer paid to you or your affiliate, either directly or indirectly, for the gas, residue gas, or gas plant products.

(f)(1) Absent contract revision or amendment, if you or your affiliate fail(s) to take proper or timely action to receive prices or benefits to which you or your affiliate are entitled, you must pay royalty based upon that obtainable price or benefit.

(2) If you or your affiliate make timely application for a price increase or benefit allowed under your or your affiliate's contract, but the purchaser refuses, and you or your affiliate take reasonable, documented measures to force purchaser compliance, you will not owe additional royalties unless or until you or your affiliate receive additional monies or consideration resulting from the price increase. You may not construe this paragraph to permit you to avoid your royalty payment obligation in situations where a purchaser fails to pay, in whole or in part, or in a timely manner, for a quantity of gas, residue gas, or gas plant products.

(g)(1) You or your affiliate must make all contracts, contract revisions, or amendments in writing.

(2) If you or your affiliate fail(s) to comply with paragraph (g)(1) of this section, ONRR may direct you to use a different measure of royalty value.

(3) This provision applies notwithstanding any other provisions in this Title 30 to the contrary.

§ 1206.144 [Reserved]

■ 14. Remove and reserve § 1206.144.

■ 15. Revise § 1206.148 to read as follows:

§ 1206.148 How do I request a valuation determination?

(a) You may request a valuation determination from ONRR regarding any gas produced. Your request must comply with all of the following:

(1) Be in writing.

(2) Identify specifically all leases involved, all interest owners of those leases, the designee(s), and the operator(s) for those leases.

(3) Completely explain all relevant facts. You must inform ONRR of any changes to relevant facts that occur before we respond to your request.

(4) Include copies of all relevant documents.

(5) Provide your analysis of the issue(s).

(6) Suggest your proposed valuation method.

(b) In response to your request, ONRR may:

(1) Request that the Assistant Secretary for Policy, Management and Budget issue a determination;

(2) Decide that ONRR will issue guidance; or

(3) Inform you in writing that ONRR will not provide a determination or guidance. Situations in which ONRR typically will not provide any determination or guidance include, but are not limited to:

(i) Requests for guidance on hypothetical situations; or

(ii) Matters that are the subject of pending litigation or administrative appeals.

(c)(1) A determination that the Assistant Secretary for Policy, Management and Budget signs is binding on both you and ONRR until the Assistant Secretary modifies or rescinds it.

(2) After the Assistant Secretary for Policy, Management and Budget issues a determination, you must make any adjustments to royalty payments that follow from the determination, and, if you owe additional royalties, you must pay the additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter.

(3) A determination that the Assistant Secretary for Policy, Management and Budget signs is the final action of the Department and is subject to judicial review under 5 U.S.C. 701–706.

(d) Guidance that ONRR issues is not binding on ONRR, delegated States, or you with respect to the specific situation addressed in the guidance.

(1) Guidance and ONRR's decision whether or not to issue guidance or to request an Assistant Secretary for Policy, Management and Budget determination, or neither, under paragraph (b) of this section, are not appealable decisions or orders under 30 CFR part 1290.

(2) If you receive an order requiring you to pay royalty on the same basis as the guidance, you may appeal that order under 30 CFR part 1290.

(e) ONRR or the Assistant Secretary for Policy, Management and Budget may use any of the applicable criteria in this subpart to provide guidance or to make a determination.

(f) A change in an applicable statute or regulation on which ONRR based any guidance, or the Assistant Secretary for Policy, Management and Budget based any determination, takes precedence over the determination or guidance after the effective date of the statute or regulation, regardless of whether ONRR or the Assistant Secretary modifies or rescinds the guidance or determination.

(g) ONRR may make requests and replies under this section available to the public, subject to the confidentiality requirements under § 1206.149.

■ 16. Revise § 1260.152 to read as follows:

§ 1206.152 What general transportation allowance requirements apply to me?

(a) ONRR will allow a deduction for the reasonable, actual costs to transport residue gas, gas plant products, or unprocessed gas from the lease to the point off of the lease under § 1206.153 or § 1206.154, as applicable. You may not deduct transportation costs that you incur when moving a particular volume of production to reduce royalties that you owe on production for which you did not incur those costs. This paragraph applies when:

(1) You value unprocessed gas under § 1206.141(b) or residue gas and gas plant products under § 1206.142(b) based on a sale at a point off of the lease, unit, or communitized area where the residue gas, gas plant products, or unprocessed gas is produced; and

(2) The movement to the sales point is not gathering.

(b) You must calculate the deduction for transportation costs based on your or your affiliate's cost of transporting each product through each individual transportation system. If your or your affiliate's transportation contract includes more than one product in a gaseous phase, you must allocate costs consistently and equitably to each of the products transported. Your allocation must use the same proportion as the ratio of the volume of each product (excluding waste products with no value) to the volume of all products in the gaseous phase (excluding waste products with no value).

(1) You may not take an allowance for transporting lease production that is not royalty-bearing.

(2) You may propose to ONRR a prospective cost allocation method based on the values of the products transported. ONRR will approve the method if it is consistent with the purposes of the regulations in this subpart.

(3) You may use your proposed procedure to calculate a transportation allowance beginning with the production month following the month when ONRR received your proposed procedure until ONRR accepts or rejects your cost allocation. If ONRR rejects your cost allocation, you must amend your Form ONRR–2014 for the months when you used the rejected method and pay any additional royalty due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter.

(c)(1) Where you or your affiliate transport(s) both gaseous and liquid products through the same transportation system, you must propose a cost allocation procedure to ONRR.

(2) You may use your proposed procedure to calculate a transportation allowance until ONRR accepts or rejects your cost allocation. If ONRR rejects your cost allocation, you must amend your Form ONRR–2014 for the months when you used the rejected method and pay any additional royalty due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter.

(3) You must submit your initial proposal, including all available data, within three months after you first claim the allocated deductions on Form ONRR–2014.

(d) If you value unprocessed gas under § 1206.141(c) or residue gas and gas plant products under § 1206.142(d), you may not take a transportation allowance.

(e)(1) Your transportation allowance may not exceed 50 percent of the value of the residue gas, gas plant products, or unprocessed gas as determined under § 1206.141 or § 1206.142, except as provided in paragraph (e)(2) of this section.

(2) You may ask ONRR to approve a transportation allowance in excess of the limitation in paragraph (e)(1) of this section. You must demonstrate that the transportation costs incurred in excess of the limitations prescribed in paragraph (e)(1) of this section were reasonable, actual, and necessary. An application for exception (using Form ONRR–4393, Request to Exceed Regulatory Allowance Limitation) must contain all relevant and supporting documentation necessary for ONRR to make a determination. Under no circumstances may the value for royalty purposes under any sales type code be reduced to zero.

(f) You must express transportation allowances for residue gas, gas plant products, or unprocessed gas as a dollar-value equivalent. If your or your affiliate's payments for transportation under a contract are not on a dollar-per-unit basis, you must convert whatever consideration that you or your affiliate are/is paid to a dollar-value equivalent.

(g) ONRR may direct you to modify your transportation allowance if:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration that you or your affiliate paid under an arm's-length transportation contract does not reflect the reasonable cost of the transportation because you breached your duty to market the gas, residue gas, or gas plant products for the mutual benefit of yourself and the lessor; or

(3) ONRR cannot determine if you properly calculated a transportation allowance under § 1206.153 or § 1206.154 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart B.

(h) You do not need ONRR's approval before reporting a transportation allowance.

■ 17. Revise § 1206.153 to read as follows:

§ 1206.153 How do I determine a transportation allowance if I have an arm's-length transportation contract?

(a)(1) If you or your affiliate incur transportation costs under an arm's-length transportation contract, you may claim a transportation allowance for the reasonable, actual costs incurred, as more fully explained in paragraph (b) of this section, except as provided in § 1206.152(g) and subject to the limitation in § 1206.152(e).

(2) You must be able to demonstrate that your or your affiliate's contract is arm's-length.

(b) Subject to the requirements of paragraph (c) of this section, you may include, but are not limited to, the following costs to determine your transportation allowance under paragraph (a) of this section; you may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section:

(1) Firm demand charges paid to pipelines. You may deduct firm demand charges or capacity reservation fees that you or your affiliate paid to a pipeline, including charges or fees for unused firm capacity that you or your affiliate have not sold before you report your allowance. If you or your affiliate receive(s) a payment from any party for release or sale of firm capacity after reporting a transportation allowance that included the cost of that unused firm capacity, or if you or your affiliate receive(s) a payment or credit from the pipeline for penalty refunds, rate case refunds, or other reasons, you must reduce the firm demand charge claimed on Form ONRR–2014 by the amount of that payment. You must modify Form ONRR–2014 by the amount received or credited for the affected reporting period and pay any resulting royalty due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter.

(2) Gas Supply Realignment (GSR) costs. The GSR costs result from a pipeline reforming or terminating supply contracts with producers in order to implement the restructuring requirements of FERC Orders in 18 CFR part 284.

(3) Commodity charges. The commodity charge allows the pipeline to recover the costs of providing service.

(4) Wheeling costs. Hub operators charge a wheeling cost for transporting gas from one pipeline to either the same or another pipeline through a market center or hub. A hub is a connected manifold of pipelines through which a series of incoming pipelines are interconnected to a series of outgoing pipelines.

(5) Gas Research Institute (GRI) fees. The GRI conducts research, development, and commercialization programs on natural gas-related topics for the benefit of the U.S. gas industry and gas customers. GRI fees are allowable, provided that such fees are mandatory in FERC-approved tariffs.

(6) Annual Charge Adjustment (ACA) fees. FERC charges these fees to pipelines to pay for its operating expenses.

(7) Payments (either volumetric or in value) for actual or theoretical losses. Theoretical losses are not deductible in transportation arrangements unless the transportation allowance is based on arm's-length transportation rates charged under a FERC or State regulatory-approved tariff. If you or your affiliate receive(s) volumes or credit for line gain, you must reduce your transportation allowance accordingly and pay any resulting royalties plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter;

(8) Temporary storage services. This includes short-duration storage services that market centers or hubs (commonly referred to as ''parking'' or ''banking'') offer or other temporary storage services that pipeline transporters provide, whether actual or provided as a matter of accounting. Temporary storage is limited to 30 days or fewer.

(9) Supplemental costs for compression, dehydration, and treatment of gas. ONRR allows these costs only if such services are required for transportation and exceed the services necessary to place production into marketable condition required under § 1206.146.

(10) Costs of surety. You may deduct the costs of securing a letter of credit, or other surety, that the pipeline requires you or your affiliate, as a shipper, to maintain under a transportation contract.

(11) Hurricane surcharges. You may deduct hurricane surcharges that you or your affiliate actually pay(s).

(c) You may not include the following costs to determine your transportation allowance under paragraph (a) of this section:

(1) Fees or costs incurred for storage. This includes storing production in a storage facility, whether on or off of the lease, for more than 30 days.

(2) Aggregator/marketer fees. This includes fees that you or your affiliate pay(s) to another person (including your affiliates) to market your gas, including purchasing and reselling the gas or finding or maintaining a market for the gas production.

(3) Penalties that you or your affiliate incur(s) as a shipper. These penalties include, but are not limited to:

(i) Over-delivery cash-out penalties. This includes the difference between the price that the pipeline pays to you or your affiliate for over-delivered volumes outside of the tolerances and the price that you or your affiliate receive(s) for over-delivered volumes within the tolerances.

(ii) Scheduling penalties. This includes penalties that you or your affiliate incur(s) for differences between daily volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point.

(iii) Imbalance penalties. This includes penalties that you or your affiliate incur(s) (generally on a monthly basis) for differences between volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point.

(iv) Operational penalties. This includes fees that you or your affiliate incur(s) for violation of the pipeline's curtailment or operational orders issued to protect the operational integrity of the pipeline.

(4) Intra-hub transfer fees. These are fees that you or your affiliate pay(s) to hub operators for administrative services (such as title transfer tracking) necessary to account for the sale of gas within a hub.

(5) Fees paid to brokers. This includes fees that you or your affiliate pay(s) to parties who arrange marketing or transportation, if such fees are separately identified from aggregator/marketer fees.

(6) Fees paid to scheduling service providers. This includes fees that you or your affiliate pay(s) to parties who

provide scheduling services, if such fees are separately identified from aggregator/marketer fees.

(7) Internal costs. This includes salaries and related costs, rent/space costs, office equipment costs, legal fees, and other costs to schedule, nominate, and account for the sale or movement of production.

(8) Other non-allowable costs. Any cost you or your affiliate incur(s) for services that you are required to provide at no cost to the lessor, including, but not limited to, costs to place your gas, residue gas, or gas plant products into marketable condition disallowed under § 1206.146 and costs of boosting residue gas disallowed under § 1202.151(b) of this chapter.

(d) If you have no written contract for the arm's-length transportation of gas, and neither you nor your affiliate perform your own transportation, you must propose to ONRR a method to determine the transportation allowance using the procedures in § 1206.148(a).

(1) You may use that method to determine your allowance until ONRR issues its determination.

(2) [RESERVED]

■ 18. Revise § 1206.157 to read as follows:

§ 1206.157 What interest and penalties apply if I improperly report a transportation allowance?

(a)(1) If ONRR determines that you took an unauthorized transportation allowance, then you must pay any additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter.

(2) If you understated your transportation allowance, you may be entitled to a credit, with interest.

(b) If you deduct a transportation allowance on Form ONRR–2014 that exceeds 50 percent of the value of the gas, residue gas, or gas plant products transported without obtaining ONRR's prior approval under § 1206.152(e)(2), you must pay additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter, on the excess allowance amount taken from the date when that amount is taken to the date when you file an exception request that ONRR approves. If you do not file an exception request, or if ONRR does not approve your request, you must pay late payment interest on the excess allowance amount taken from the date that amount is taken until the date you pay the additional royalties owed.

(c) If you improperly net a transportation allowance against the sales value of the residue gas, gas plant products, or unprocessed gas instead of reporting the allowance as a separate entry on Form ONRR–2014, ONRR may assess a civil penalty under 30 CFR part 1241.

■ 19. Revise § 1206.159 to read as follows:

§ 1206.159 What general processing allowances requirements apply to me?

(a)(1) When you value any gas plant product under § 1206.142(c), you may deduct from the value the reasonable, actual costs of processing.

(2) You do not need ONRR's approval before reporting a processing allowance.

(b) You must allocate processing costs among the gas plant products. You must determine a separate processing allowance for each gas plant product and processing plant relationship. ONRR considers NGLs to be one product.

(c)(1) You may not apply the processing allowance against the value of the residue gas, except as provided in paragraph (c)(4) of this section.

(2) The processing allowance deduction on the basis of an individual product may not exceed 66⅔ percent of the value of each gas plant product determined under § 1206.142(c), except as provided under paragraphs (c)(3) or (4) of this section. Before you calculate the 66⅔-percent limit, you must first reduce the value for any transportation allowances related to post-processing transportation authorized under § 1206.152.

(3) You may ask ONRR to approve a processing allowance in excess of the limitation prescribed by paragraph (c)(2) of this section. You must demonstrate that the processing costs incurred in excess of the limitation prescribed in paragraph (c)(2) of this section were reasonable, actual, and necessary. An application for exception (using Form ONRR–4393, Request to Exceed Regulatory Allowance Limitation) must contain all relevant and supporting documentation for ONRR to make a determination. Under no circumstances may the value for royalty purposes of any gas plant product be reduced to zero.

(4) If you incur extraordinary costs for processing gas, you may apply to ONRR for an allowance for those costs which must be in addition to any other processing allowance to which the lessee is entitled pursuant to this section. You must demonstrate that the costs are, by reference to standard industry conditions and practice, extraordinary, unusual, or unconventional. You are not required to receive ONRR approval to continue an extraordinary processing allowance. However, you must report the deduction to ONRR in a form and manner prescribed by ONRR in order to retain the ability to deduct the allowance.

(d)(1) ONRR will not allow a processing cost deduction for the costs of placing lease products in marketable condition, including dehydration, separation, compression, or storage, even if those functions are performed off the lease or at a processing plant.

(2) Where gas is processed for the removal of acid gases, commonly referred to as ''sweetening,'' ONRR will not allow processing cost deductions for such costs unless the acid gases removed are further processed into a gas plant product.

(i) In such event, you are eligible for a processing allowance determined under this subpart.

(ii) ONRR will not grant any processing allowance for processing lease production that is not royalty bearing.

(e) ONRR may direct you to modify your processing allowance if:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration that you or your affiliate paid under an arm's-length processing contract does not reflect the reasonable cost of the processing because you breached your duty to market the gas, residue gas, or gas plant products for the mutual benefit of yourself and the lessor; or

(3) ONRR cannot determine if you properly calculated a processing allowance under § 1206.160 or § 1206.161 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart B.

■ 20. Revise § 1206.160 to read as follows:

§ 1206.160 How do I determine a processing allowance if I have an arm's-length processing contract?

(a)(1) If you or your affiliate incur processing costs under an arm's-length processing contract, you may claim a processing allowance for the reasonable, actual costs incurred, as more fully explained in paragraph (b) of this section, except as provided in § 1206.159(e) and subject to the limitation in § 1206.159(c)(2).

(2) You must be able to demonstrate that your or your affiliate's contract is arm's-length.

(b)(1) If your or your affiliate's arm's-length processing contract includes more than one gas plant product, and you can determine the processing costs for each product based on the contract, then you must determine the processing costs for each gas plant product under the contract.

(2) If your or your affiliate's arm's-length processing contract includes more than one gas plant product, and you cannot determine the processing costs attributable to each product from the contract, you must propose an allocation procedure to ONRR.

(i) You may use your proposed allocation procedure until ONRR issues its determination.

(ii) You must submit all relevant data to support your proposal.

(iii) ONRR will determine the processing allowance based upon your proposal and any additional information that ONRR deems necessary.

(iv) You must submit the allocation proposal within three months of claiming the allocated deduction on Form ONRR–2014.

(3) You may not take an allowance for the costs of processing lease production that is not royalty-bearing.

(4) If your or your affiliate's payments for processing under an arm's-length contract are not based on a dollar-per-unit basis, you must convert whatever consideration that you or your affiliate paid to a dollar-value equivalent.

(c) If you have no written contract for the arm's-length processing of gas, and neither you nor your affiliate perform your own processing, you must propose to ONRR a method to determine the processing allowance using the procedures in § 1206.148(a).

(1) You may use that method to determine your allowance until ONRR issues a determination.

(2) [RESERVED]

■ 21. Revise § 1206.164 to read as follows:

§ 1206.164 What interest and penalties apply if I improperly report a processing allowance?

(a)(1) If ONRR determines that you took an unauthorized processing allowance, then you must pay any additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter.

(2) If you understated your processing allowance, you may be entitled to a credit, with interest.

(b) If you deduct a processing allowance on Form ONRR–2014 that exceeds 66⅔ percent of the value of a gas plant product without obtaining ONRR's prior approval under § 1206.159(c)(3), you must pay additional royalties due, plus late payment interest calculated under §§ 1218.54 and 1218.102 of this chapter, on the excess allowance amount taken from the date when that amount is taken to the date when you file an exception request that ONRR approves. If you do not file an exception request, or if ONRR does not approve your request, you must pay late payment interest on the excess allowance amount taken from the date that amount is taken until the date you pay the additional royalties owed.

(c) If you improperly net a processing allowance against the sales value of a gas plant product instead of reporting the allowance as a separate entry on Form ONRR–2014, ONRR may assess a civil penalty under 30 CFR part 1241.

Subpart F—Federal Coal

■ 22. Revise § 1206.252 to read as follows:

§ 1206.252 How do I calculate royalty value for coal that I or my affiliate sells under an arm's-length or non-arm's-length contract?

(a) The value of coal under this section for royalty purposes is the gross proceeds accruing to you or your affiliate under the first arm's-length contract, less an applicable transportation allowance determined under §§ 1206.260 through 1206.262 and washing allowance under §§ 1206.267 through 1206.269. You must use this paragraph (a) to value coal when:

(1) You sell under an arm's-length contract; or

(2) You sell or transfer to your affiliate or another person under a non-arm's-length contract, and that affiliate or person, or another affiliate of either of them, then sells the coal under an arm's-length contract.

(b) If you have no contract for the sale of coal subject to this section because you or your affiliate used the coal in a power plant that you or your affiliate own(s) for the generation and sale of electricity:

(i) You must propose to ONRR a method to determine the value using the procedures in § 1206.258(a).

(ii) You must use that method to determine value, for royalty purposes, until ONRR issues a determination.

(iii) After ONRR issues a determination, you must make the adjustments, if any, under § 1206.253(a)(2).

(c) If you are entitled to take a washing allowance and transportation allowance for royalty purposes under this section, under no circumstances may the washing allowance plus the transportation allowance reduce the royalty value of the coal to zero.

■ 23. Revise § 1206.253 to read as follows:

§ 1206.253 How will ONRR determine if my royalty payments are correct?

(a)(1) ONRR may monitor, review, and audit the royalties that you report, and, if ONRR determines that your reported value is inconsistent with the requirements of this subpart, ONRR may establish a reasonable royalty value based on other relevant matters.

(2) If ONRR directs you to use a different royalty value, you must either pay any underpaid royalties due, plus late payment interest calculated under § 1218.202 of this chapter, or report a credit for—or request a refund of—any overpaid royalties.

(b) ONRR may examine whether your or your affiliate's contract reflects the total consideration transferred for Federal coal, either directly or indirectly, from the buyer to you or your affiliate. If ONRR determines that additional consideration beyond that reflected in the contract was transferred, or that any portion of the consideration was not included in gross proceeds reported, ONRR may establish a reasonable royalty value based on other relevant matters.

(c) ONRR may establish a reasonable royalty value based on other relevant matters if ONRR determines that the gross proceeds accruing to you or your affiliate under a contract do not reflect reasonable consideration because:

(1) There is misconduct by or between the contracting parties;

(2) You breached your duty to market the coal for the mutual benefit of yourself and the lessor; or

(3) ONRR cannot determine if you properly valued your coal under § 1206.252 for any reason, including, but not limited to, your or your affiliate's failure to provide documents to ONRR under 30 CFR part 1212, subpart E.

(d) You have the burden of demonstrating that your or your affiliate's contract is arm's-length.

(e) ONRR may require you to certify that the provisions in your or your affiliate's contract include(s) all of the consideration that the buyer paid to you or your affiliate, either directly or indirectly, for the coal.

(f)(1) Absent any contract revisions or amendments, if you or your affiliate fail(s) to take proper or timely action to receive prices or benefits to which you or your affiliate are entitled, you must pay royalty based upon that obtainable price or benefit.

(2) If you or your affiliate apply in a timely manner for a price increase or benefit allowed under your or your affiliate's contract, but the purchaser refuses, and you or your affiliate take reasonable, documented measures to force purchaser compliance, you will not owe additional royalties unless or until you or your affiliate receive additional monies or consideration

resulting from the price increase. You may not construe this paragraph to permit you to avoid your royalty payment obligation in situations where a purchaser fails to pay in whole or in part, or in a timely manner, for a quantity of coal.

(g)(1) You or your affiliate must make all contracts, contract revisions, or amendments in writing.

(2) If you or your affiliate fail(s) to comply with paragraph (g)(1) of this section, ONRR may establish a reasonable royalty value based on other relevant matters.

(3) This provision applies notwithstanding any other provisions in this title 30 to the contrary.

§ 1206.254 [Reserved]

■ 24. Remove and reserve § 1206.254.

■ 25. Revise § 1206.258 to read as follows:

§ 1206.258 How do I request a valuation determination?

(a) You may request a valuation determination from ONRR regarding any coal produced. Your request must comply with all of the following:

(1) Be in writing.

(2) Identify specifically all leases involved, all interest owners of those leases, and the operator(s) for those leases.

(3) Completely explain all relevant facts. You must inform ONRR of any changes to relevant facts that occur before we respond to your request.

(4) Include copies of all relevant documents.

(5) Provide your analysis of the issue(s).

(6) Suggest a proposed valuation method.

(b) In response to your request, ONRR may:

(1) Request that the Assistant Secretary for Policy, Management and Budget issue a determination;

(2) Decide that ONRR will issue guidance; or

(3) Inform you in writing that ONRR will not provide a determination or guidance. Situations in which ONRR typically will not provide any determination or guidance include, but are not limited to:

(i) Requests for guidance on hypothetical situations; or

(ii) Matters that are the subject of pending litigation or administrative appeals.

(c)(1) A determination that the Assistant Secretary for Policy, Management and Budget signs is binding on both you and ONRR until the Assistant Secretary modifies or rescinds it.

(2) After the Assistant Secretary for Policy, Management and Budget issues a determination, you must make any adjustments in royalty payments that follow from the determination and, if you owe additional royalties, you must pay any additional royalties due, plus late payment interest calculated under § 1218.202 of this chapter.

(3) A determination that the Assistant Secretary for Policy, Management and Budget signs is the final action of the Department and is subject to judicial review under 5 U.S.C. 701–706.

(d) Guidance that ONRR issues is not binding on ONRR, delegated States, or you with respect to the specific situation addressed in the guidance.

(1) Guidance and ONRR's decision whether or not to issue guidance or to request an Assistant Secretary for Policy, Management and Budget determination, or neither, under paragraph (b) of this section, are not appealable decisions or orders under 30 CFR part 1290.

(2) If you receive an order requiring you to pay royalty on the same basis as the guidance, you may appeal that order under 30 CFR part 1290.

(e) ONRR or the Assistant Secretary for Policy, Management and Budget may use any of the applicable criteria in this subpart to provide guidance or to make a determination.

(f) A change in an applicable statute or regulation on which ONRR based any guidance, or the Assistant Secretary for Policy, Management and Budget based any determination, takes precedence over the determination or guidance after the effective date of the statute or regulation, regardless of whether ONRR or the Assistant Secretary modifies or rescinds the guidance or determination.

(g) ONRR or the Assistant Secretary for Policy, Management and Budget generally will not retroactively modify or rescinds a valuation determination issued under paragraph (d) of this section, unless:

(1) There was a misstatement or omission of material facts; or

(2) The facts subsequently developed are materially different from the facts on which the guidance was based.

(h) ONRR may make requests and replies under this section available to the public, subject to the confidentiality requirements under § 1206.259.

■ 26. Revise § 1206.260 to read as follows:

§ 1206.260 What general transportation allowance requirements apply to me?

(a)(1) ONRR will allow a deduction for the reasonable, actual costs to transport coal from the lease to the point off of the lease or mine as determined under § 1206.261 or 1206.262, as applicable.

(2) You do not need ONRR's approval before reporting a transportation allowance for costs incurred.

(b) You may take a transportation allowance when:

(1) You value coal under § 1206.252;

(2) You transport the coal from a Federal lease to a sales point, which is remote from both the lease and mine; or

(3) You transport the coal from a Federal lease to a wash plant when that plant is remote from both the lease and mine and, if applicable, from the wash plant to a remote sales point.

(c) You may not take an allowance for:

(1) Transporting lease production that is not royalty-bearing;

(2) In-mine movement of your coal; or

(3) Costs to move a particular tonnage of production for which you did not incur those costs.

(d) You may only claim a transportation allowance when you sell the coal and pay royalties.

(e) You must allocate transportation allowances to the coal attributed to the lease from which it was extracted.

(1) If you commingle coal produced from Federal and non-Federal leases, you may not disproportionately allocate transportation costs to Federal lease production. Your allocation must use the same proportion as the ratio of the tonnage from the Federal lease production to the tonnage from all production.

(2) If you commingle coal produced from more than one Federal lease, you must allocate transportation costs to each Federal lease, as appropriate. Your allocation must use the same proportion as the ratio of the tonnage of each Federal lease production to the tonnage of all production.

(3) For washed coal, you must allocate the total transportation allowance only to washed products.

(4) For unwashed coal, you may take a transportation allowance for the total coal transported.

(5)(i) You must report your transportation costs on Form ONRR–4430 as clean coal short tons sold during the reporting period multiplied by the sum of the per-short-ton cost of transporting the raw tonnage to the wash plant and, if applicable, the per-short-ton cost of transporting the clean coal tons from the wash plant to a remote sales point.

(ii) You must determine the cost per short ton of clean coal transported by dividing the total applicable transportation cost by the number of clean coal tons resulting from washing the raw coal transported.

(f) You must express transportation allowances for coal as a dollar-value equivalent per short ton of coal transported. If you do not base your or your affiliate's payments for transportation under a transportation contract on a dollar-per-unit basis, you must convert whatever consideration that you or your affiliate paid to a dollar-value equivalent.

(g) ONRR may determine your transportation allowance if:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration that you or your affiliate paid under an arm's-length transportation contract does not reflect the reasonable cost of the transportation because you breached your duty to market the coal for the mutual benefit of yourself and the lessor by transporting your coal at a cost that is unreasonably high; or

(3) ONRR cannot determine if you properly calculated a transportation allowance under § 1206.261 or § 1206.262 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart E.

■ 27. Revise § 1206.261 to read as follows:

§ 1206.261 How do I determine a transportation allowance if I have an arm's-length transportation contract?

(a) If you or your affiliate incur(s) transportation costs under an arm's-length transportation contract, you may claim a transportation allowance for the reasonable, actual costs incurred for transporting the coal under that contract.

(b) You must be able to demonstrate that your or your affiliate's contract is at arm's-length.

(c) If you have no written contract for the arm's-length transportation of coal, and neither you nor your affiliate perform your own transportation, you must propose to ONRR a method to determine the transportation allowance using the procedures in § 1206.258(a).

(1) You must use that method to determine your allowance until ONRR issues a determination.

(2) [RESERVED]

■ 28. Revise § 1206.267 to read as follows:

§ 1206.267 What general washing allowance requirements apply to me?

(a)(1) If you determine the value of your coal under § 1206.252, you may take a washing allowance for the reasonable, actual costs to wash the coal. The allowance is a deduction when determining coal royalty value for the costs that you incur to wash coal.

(2) You do not need ONRR's approval before reporting a washing allowance.

(b) You may not:

(1) Take an allowance for the costs of washing lease production that is not royalty bearing.

(2) Disproportionately allocate washing costs to Federal leases. You must allocate washing costs to washed coal attributable to each Federal lease by multiplying the input ratio determined under § 1206.251(e)(2)(i) by the total allowable costs.

(c)(1) You must express washing allowances for coal as a dollar-value equivalent per short ton of coal washed.

(2) If you do not base your or your affiliate's payments for washing under an arm's-length contract on a dollar-per-unit basis, you must convert whatever consideration that you or your affiliate paid to a dollar-value equivalent.

(d) ONRR may direct you to modify your washing allowance if:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration that you or your affiliate paid under an arm's-length washing contract does not reflect the reasonable cost of the washing because you breached your duty to market the coal for the mutual benefit of yourself and the lessor by washing your coal at a cost that is unreasonably high; or

(3) ONRR cannot determine if you properly calculated a washing allowance under §§ 1206.267 through 1206.269 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart E.

(e) You may only claim a washing allowance when you sell the washed coal and report and pay royalties.

■ 29. Revise § 1206.268 to read as follows:

§ 1206.268 How do I determine washing allowances if I have an arm's-length washing contract or no written arm's-length contract?

(a) If you or your affiliate incur(s) washing costs under an arm's-length washing contract, you may claim a washing allowance for the reasonable, actual costs incurred.

(b) You must be able to demonstrate that your or your affiliate's washing contract is arm's-length.

(c) If you have no written contract for the arm's-length washing of coal, and neither you nor your affiliate perform your own washing, you must propose to ONRR a method to determine the washing allowance using the procedures in § 1206.258(a).

(1) You must use that method to determine your allowance until ONRR issues a determination.

(2) [RESERVED]

Subpart J—Indian Coal

■ 30. Revise § 1206.452 to read as follows:

§ 1206.452 How do I calculate royalty value for coal that I or my affiliate sell(s) under an arm's-length or non-arm's-length contract?

(a) The value of coal under this section for royalty purposes is the gross proceeds accruing to you or your affiliate under the first arm's-length contract, less an applicable transportation allowance determined under §§ 1206.460 through 1206.462 and washing allowance under §§ 1206.467 through 1206.469. You must use this paragraph (a) to value coal when:

(1) You sell under an arm's-length contract; or

(2) You sell or transfer to your affiliate or another person under a non-arm's-length contract, and that affiliate or person, or another affiliate of either of them, then sells the coal under an arm's-length contract.

(b) If you have no contract for the sale of coal subject to this section because you or your affiliate used the coal in a power plant that you or your affiliate own(s) for the generation and sale of electricity:

(i) You must propose to ONRR a method to determine the value using the procedures in § 1206.458(a).

(ii) You must use that method to determine value, for royalty purposes, until ONRR issues a determination.

(iii) After ONRR issues a determination, you must make the adjustments under § 1206.453(a)(2).

(c) If you are entitled to take a washing allowance and transportation allowance for royalty purposes under this section, under no circumstances may the washing allowance plus the transportation allowance reduce the royalty value of the coal to zero.

■ 31. Revise § 1206.453 to read as follows:

§ 1206.453 How will ONRR determine if my royalty payments are correct?

(a)(1) ONRR may monitor, review, and audit the royalties that you report, and, if ONRR determines that your reported value is inconsistent with the requirements of this subpart, ONRR may establish a reasonable royalty value based on other relevant matters.

(2) If ONRR directs you to use a different royalty value, you must either pay any underpaid royalties due, plus

late payment interest calculated under § 1218.202 of this chapter, or report a credit for—or request a refund of—any overpaid royalties.

(b) ONRR may examine whether your or your affiliate's contract reflects the total consideration transferred for Indian coal, either directly or indirectly, from the buyer to you or your affiliate. If ONRR determines that additional consideration beyond that reflected in the contract was transferred, or that any portion of the consideration was not included in gross proceeds reported, ONRR may establish a reasonable royalty value based on other relevant matters.

(c) ONRR may establish a reasonable royalty value based on other relevant matters if ONRR determines that the gross proceeds accruing to you or your affiliate under a contract do not reflect reasonable consideration because:

(1) There is misconduct by or between the contracting parties;

(2) You breached your duty to market the coal for the mutual benefit of yourself and the lessor; or

(3) ONRR cannot determine if you properly valued your coal under § 1206.452 for any reason, including, but not limited to, your or your affiliate's failure to provide documents to ONRR under 30 CFR part 1212, subpart E.

(d) You have the burden of demonstrating that your or your affiliate's contract is arm's-length.

(e) ONRR may require you to certify that the provisions in your or your affiliate's contract include(s) all of the consideration that the buyer paid to you or your affiliate, either directly or indirectly, for the coal.

(f)(1) Absent any contract revisions or amendments, if you or your affiliate fail(s) to take proper or timely action to receive prices or benefits to which you or your affiliate are entitled, you must pay royalty based upon that obtainable price or benefit.

(2) If you or your affiliate apply in a timely manner for a price increase or benefit allowed under your or your affiliate's contract, but the purchaser refuses, and you or your affiliate take reasonable, documented measures to force purchaser compliance, you will not owe additional royalties unless or until you or your affiliate receive additional monies or consideration resulting from the price increase. You may not construe this paragraph to permit you to avoid your royalty payment obligation in situations where a purchaser fails to pay in whole or in part, or in a timely manner, for a quantity of coal.

(g)(1) You or your affiliate must make all contracts, contract revisions, or amendments in writing.

(2) If you or your affiliate fail(s) to comply with paragraph (g)(1) of this section, ONRR may establish a reasonable royalty value based on other relevant matters.

(3) This provision applies notwithstanding any other provisions in this title 30 to the contrary.

§ 1206.454 [Removed and reserved]

■ 32. Remove and reserve § 1206.454.

■ 33. Revise § 1206.458 to read as follows:

§ 1206.458 How do I request a valuation determination?

(a) You may request a valuation determination from ONRR regarding any coal produced. Your request must comply with all of the:

(1) Be in writing.

(2) Identify specifically all leases involved, all interest owners of those leases, and the operator(s) for those leases.

(3) Completely explain all relevant facts. You must inform ONRR of any changes to relevant facts that occur before we respond to your request.

(4) Include copies of all relevant documents.

(5) Provide your analysis of the issue(s).

(6) Suggest a proposed valuation method.

(b) In response to your request, ONRR may:

(1) Request that the Assistant Secretary for Policy, Management and Budget issue a determination;

(2) Decide that ONRR will issue guidance; or

(3) Inform you in writing that ONRR will not provide a determination or guidance. Situations in which ONRR typically will not provide any determination or guidance include, but are not limited to:

(i) Requests for guidance on hypothetical situations; or

(ii) Matters that are the subject of pending litigation or administrative appeals.

(c)(1) A determination that the Assistant Secretary for Policy, Management and Budget signs is binding on both you and ONRR until the Assistant Secretary modifies or rescinds it.

(2) After the Assistant Secretary for Policy, Management and Budget issues a determination, you must make any adjustments in royalty payments that follow from the determination and, if you owe additional royalties, you must pay any additional royalties due, plus late payment interest calculated under § 1218.202 of this chapter.

(3) A determination that the Assistant Secretary for Policy, Management and Budget signs is the final action of the Department and is subject to judicial review under 5 U.S.C. 701–706.

(d) Guidance that ONRR issues is not binding on ONRR, delegated States, or you with respect to the specific situation addressed in the guidance.

(1) Guidance and ONRR's decision whether or not to issue guidance or to request an Assistant Secretary for Policy, Management and Budget determination, or neither, under paragraph (b) of this section, are not appealable decisions or orders under 30 CFR part 1290.

(2) If you receive an order requiring you to pay royalty on the same basis as the guidance, you may appeal that order under 30 CFR part 1290.

(e) ONRR or the Assistant Secretary for Policy, Management and Budget may use any of the applicable criteria in this subpart to provide guidance or to make a determination.

(f) A change in an applicable statute or regulation on which ONRR based any guidance, or the Assistant Secretary for Policy, Management and Budget based any determination, takes precedence over the determination or guidance after the effective date of the statute or regulation, regardless of whether ONRR or the Assistant Secretary modifies or rescinds the guidance or determination.

(g) ONRR or the Assistant Secretary for Policy, Management and Budget generally will not retroactively modify or rescind a valuation determination issued under paragraph (d) of this section, unless:

(1) There was a misstatement or omission of material facts; or

(2) The facts subsequently developed are materially different from the facts on which the guidance was based.

(h) ONRR may make requests and replies under this section available to the public, subject to the confidentiality requirements under § 1206.259.

■ 34. Revise § 1206.460 to read as follows:

§ 1206.460 What general transportation allowance requirements apply to me?

(a)(1) ONRR will allow a deduction for the reasonable, actual costs to transport coal from the lease to the point off of the lease or mine as determined under § 1206.461 or 1206.462, as applicable.

(2) You do not need ONRR's approval before reporting a transportation allowance for costs incurred.

(b) You may take a transportation allowance when:

(1) You value coal under § 1206.452;

(2) You transport the coal from a Federal lease to a sales point, which is remote from both the lease and mine; or

(3) You transport the coal from a Federal lease to a wash plant when that plant is remote from both the lease and mine and, if applicable, from the wash plant to a remote sales point.

(c) You may not take an allowance for:

(1) Transporting lease production that is not royalty-bearing;

(2) In-mine movement of your coal; or

(3) Costs to move a particular tonnage of production for which you did not incur those costs.

(d) You may only claim a transportation allowance when you sell the coal and pay royalties.

(e) You must allocate transportation allowances to the coal attributed to the lease from which it was extracted.

(1) If you commingle coal produced from Federal and non-Federal leases, you may not disproportionately allocate transportation costs to Federal lease production. Your allocation must use the same proportion as the ratio of the tonnage from the Federal lease production to the tonnage from all production.

(2) If you commingle coal produced from more than one Federal lease, you must allocate transportation costs to each Federal lease, as appropriate. Your allocation must use the same proportion as the ratio of the tonnage of each Federal lease production to the tonnage of all production.

(3) For washed coal, you must allocate the total transportation allowance only to washed products.

(4) For unwashed coal, you may take a transportation allowance for the total coal transported.

(5)(i) You must report your transportation costs on Form ONRR–4430 as clean coal short tons sold during the reporting period multiplied by the sum of the per-short-ton cost of transporting the raw tonnage to the wash plant and, if applicable, the per-short-ton cost of transporting the clean coal tons from the wash plant to a remote sales point.

(ii) You must determine the cost per short ton of clean coal transported by dividing the total applicable transportation cost by the number of clean coal tons resulting from washing the raw coal transported.

(f) You must express transportation allowances for coal as a dollar-value equivalent per short ton of coal transported. If you do not base your or your affiliate's payments for transportation under a transportation contract on a dollar-per-unit basis, you must convert whatever consideration that you or your affiliate paid to a dollar-value equivalent.

(g) ONRR may determine your transportation allowance if:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration that you or your affiliate paid under an arm's-length transportation contract does not reflect the reasonable cost of the transportation because you breached your duty to market the coal for the mutual benefit of yourself and the lessor by transporting your coal at a cost that is unreasonably high; or

(3) ONRR cannot determine if you properly calculated a transportation allowance under § 1206.461 or 1206.462 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart E.

■ 35. Revise § 1206.461 to read as follows:

§ 1206.461 How do I determine a transportation allowance if I have an arm's-length transportation contract?

(a) If you or your affiliate incur(s) transportation costs under an arm's-length transportation contract, you may claim a transportation allowance for the reasonable, actual costs incurred for transporting the coal under that contract.

(b) You must be able to demonstrate that your or your affiliate's contract is at arm's-length.

(c) If you have no written contract for the arm's-length transportation of coal, then you must propose to ONRR a method to determine the allowance using the procedures in § 1206.458(a). You may use that method to determine your allowance until ONRR issues a determination.

(1) You must use that method to determine your allowance until ONRR issues a determination.

(2) [RESERVED]

■ 36. Revise § 1260.467 to read as follows:

§ 1206.467 What general washing allowance requirements apply to me?

(a)(1) If you determine the value of your coal under § 1206.452, you may take a washing allowance for the reasonable, actual costs to wash the coal. The allowance is a deduction when determining coal royalty value for the costs that you incur to wash coal.

(2) You do not need ONRR's approval before reporting a washing allowance.

(b) You may not:

(1) Take an allowance for the costs of washing lease production that is not royalty bearing.

(2) Disproportionately allocate washing costs to Federal leases. You must allocate washing costs to washed coal attributable to each Federal lease by multiplying the input ratio determined under § 1206.451(e)(2)(i) by the total allowable costs.

(c)(1) You must express washing allowances for coal as a dollar-value equivalent per short ton of coal washed.

(2) If you do not base your or your affiliate's payments for washing under an arm's-length contract on a dollar-per-unit basis, you must convert whatever consideration that you or your affiliate paid to a dollar-value equivalent.

(d) ONRR may direct you to modify your washing allowance if:

(1) There is misconduct by or between the contracting parties;

(2) ONRR determines that the consideration that you or your affiliate paid under an arm's-length washing contract does not reflect the reasonable cost of the washing because you breached your duty to market the coal for the mutual benefit of yourself and the lessor by washing your coal at a cost that is unreasonably high; or

(3) ONRR cannot determine if you properly calculated a washing allowance under §§ 1206.467 through 1206.469 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart E.

(e) You may only claim a washing allowance when you sell the washed coal and report and pay royalties.

■ 37. Revise § 1206.468 to read as follows:

§ 1206.468 How do I determine washing allowances if I have an arm's-length washing contract or no written arm's-length contract?

(a) If you or your affiliate incur(s) washing costs under an arm's-length washing contract, you may claim a washing allowance for the reasonable, actual costs incurred.

(b) You must be able to demonstrate that your or your affiliate's contract is arm's-length.

(c) If you have no written contract for the arm's-length washing of coal, and neither you nor your affiliate perform your own washing, you must propose to ONRR a method to determine the washing allowance using the procedures in § 1206.458(a).

(1) You may use that method to determine your allowance until ONRR issues a determination.

(2) [RESERVED]

PART 1241—PENALTIES

■ 38. The authority citation for part 1241 continues to read as follows:

Authority: 25 U.S.C. 396 *et seq.,* 396a *et seq.,* 2101 *et seq.;* 30 U.S.C. 181 *et seq.,* 351 *et seq.,* 1001 *et seq.,* 1701 *et seq.;* 43 U.S.C. 1301 *et seq.,* 1331 *et seq.,* 1801 *et seq.*

Subpart A—General Provisions

■ 39. Revise § 1241.11 to read as follows:

§ 1241.11 Does my hearing request affect a penalty?

(a) If you do not correct the violation identified in a Notice, any penalty will continue to accrue, even if you request a hearing, except as provided in paragraph (b) of this section.

(b) Standards and procedures for obtaining a stay. If you request in a timely manner a hearing on a Notice, you may petition the DCHD to stay the assessment or accrual of penalties pending the hearing on the record and a decision by the ALJ under § 1241.8.

(1) You must file your petition for stay within 45 calendar days after you receive a Notice.

(2) You must file your petition for stay under 43 CFR 4.21(b), in which event:

(i) We may file a response to your petition within 30 days after service.

(ii) The 45-day requirement set out in 43 CFR 4.21(b)(4) for the ALJ to grant or deny the petition does not apply.

(3) If the ALJ determines that a stay is warranted, the ALJ will issue an order granting your petition, subject to your satisfaction of the following condition: Within 10 days of your receipt of the order, you must post a bond or other surety instrument using the same standards and requirements as prescribed in 30 CFR part 1243, subpart B; or demonstrate financial solvency using the same standards and requirements as prescribed in 30 CFR part 1243, subpart C, for any specified, unpaid principal amount that is the subject of the Notice, any interest accrued on the principal, and the amount of any penalty set out in a Notice accrued up to the date of the ALJ order conditionally granting your petition.

(4)(i) If you satisfy the condition to post a bond or surety instrument or demonstrate financial solvency under paragraph (b)(3) of this section, the accrual of penalties will be stayed effective on the date of the ALJ's order conditionally granting your petition.

(ii) If you fail to satisfy the condition to post a bond or surety instrument or demonstrate financial solvency under paragraph (b)(3) of this section, penalties will continue to accrue.

Subpart C—Penalty Amount, Interest, and Collections

■ 40. Revise § 1241.70 to read as follows:

§ 1241.70 How does ONRR decide the amount of the penalty to assess?

(a) ONRR will determine the amount of the penalty to assess by considering:

(1) The severity of the violation.

(2) Your history of noncompliance.

(3) The size of your business. To determine the size of your business, we may consider the number of employees in your company, parent company or companies, and any subsidiaries and contractors.

(b) For payment violations only, we will consider the unpaid, underpaid, or late payment amount in our analysis of the severity of the violation.

(c) We will post the FCCP and ILCP assessment matrices and any adjustments to the matrices on our website.

(d) After we provisionally determine the civil penalty amount using the criteria and matrices described in paragraphs (a), (b), and (c) of this section, we may adjust the penalty amount in the FCCP or ILCP upward or downward if we find aggravating or mitigating circumstances.

(1) Aggravating circumstances may include, but are not limited to:

(i) Committing a violation because you determined that the cost of a potential penalty is less than the cost of compliance; and

(ii) Committing a violation where you have no recent history of noncompliance of the same type, but you have a history of noncompliance of other violation types.

(iii) Committing a violation that is also a criminal act.

(2) Mitigating circumstances may include, but are not limited to:

(i) Operational impacts resulting from the unexpected illness or death of an employee, natural disasters, pandemics, acts of terrorism, civil unrest, or armed conflict;

(ii) Delays caused by government action or inaction, including as a result of a government shutdown and ONRR-system downtime; and

(iii) Good faith efforts to comply with formal or informal agency guidance.

[FR Doc. 2020–17513 Filed 9–30–20; 8:45 am]

BILLING CODE 4335–30–P